Fuel Capability Demonstration Test Report 4 for the JEA Large-Scale CFB Combustion Demonstration Project

80 / 20 Blend Petroleum Coke and Pittsburgh 8 Coal Fuel

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JEA

Building Community

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1.0 INTRODUCTION

The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate fuel flexibility of the unit to utilize a variety of different fuels. Therefore, it was necessary for JEA to demonstrate this capability through a series of tests.

The purpose of the test program was to document the ability of the unit to utilize a variety of fuels and fuel blends in a cost effective and environmentally responsible manner. Fuel flexibility would be quantified by measuring the following parameters:

- Boiler efficiency
- CFB boiler sulfur capture
- AQCS sulfur and particulate capture
- The following flue gas emissions
  - Particulate matter (PM)
  - Oxides of nitrogen (NO_x)
  - Sulfur dioxide (SO_2)
  - Carbon monoxide (CO)
  - Carbon dioxide (CO_2)
  - Ammonia (NH_3)
  - Lead (Pb)
  - Mercury (Hg)
  - Fluorine (F)
  - Dioxin
  - Furan
- Stack opacity

This test report documents the results of JEA's Fuel Capability Demonstration Tests firing a 80/20 blend of Petroleum Coke and Pittsburgh 8 coal for the JEA Large-Scale CFB Combustion Demonstration Project. The term "blend" will be used throughout this report to describe the 80/20 blend of the two fuels. The tests were conducted in accordance with the Fuel Demonstration Test Protocol in Attachment A.

Throughout this report, unless otherwise indicated, the term "unit" refers to the combination of the circulating fluidized bed (CFB) boiler and the air quality control system (AQCS). The AQCS consists of a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

1.1 Test Schedule

Unit 2 of the JEA Northside plant site is a Circulating Fluidized Bed Steam Generator designed and constructed by Foster-Wheeler. The steam generator was designed to deliver main steam to the steam turbine at a flow rate of 1,993,591 lb/hr, at a throttle pressure of 2,500 psig, and at a throttle temperature of 1,000 deg F when firing Pittsburgh 8 coal.

The fuel capability demonstration test for the unit firing the blended coal was conducted over a four (4) day period beginning on August 10, 2004 and completed on August 13, 2004. During that four (4) day period, data were taken in accordance with the Test Protocol (Attachment A) while the unit was operating at 100% load, 80% load, and 60% load. The 40% load was cancelled due to Hurricane Charley which came ashore as a Category 4 hurricane on August 13, 2004 and traveled northeast towards the Jacksonville, Florida area. There are no plans to run this partial load test.

The following log represents the sequence of testing:

- Day 1 August 10, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 0932 hours; completed at 2006 hours.
  - Coal feeder B1 tripped at 0805 hours; taken out of service at 0900 hours. The test was run with this feeder out of service.
  - Boiler performance testing commenced at 0930 hours; completed at 1330 hours.

- Day 2 August 11, 2004:
  - Unit at 100% load - turbine load set and maintained at approx. 300 MW.
  - Flue gas testing commenced at 0800 hours; completed at 1656 hours.
  - Boiler performance testing commenced at 0800 hours; completed at 1200 hours

- Day 3 August 12, 2004:
  - Unit at 80% load - turbine load set and maintained at approx. 240 MW.
  - Unit began 2-hour stabilization period at 240 MW at 2230 hours.
  - Coal feeder E1 tripped; decision was made to leave it out of service for the remainder of the 80% load test.
  - Boiler performance testing commenced at 0030 hours (8/13/04) after stabilization period completed; test completed at 0430 hours.
  - Flue gas emissions data taken and recorded by CEMS system.

- Day 4 August 12 / 13, 2004:
  - Unit began ramp down to approximately 60% load; began 2-hour stabilization period at 180 MW at 2000 hours.
  - Boiler performance testing commenced at 0045 hours after stabilization period completed; test completed at 0445 hours, Aug. 13, 2004.
  - Flue gas emissions data taken and recorded by CEMS system.

1.2 Abbreviations

Following is a definition of abbreviations used in this report. Note that at their first use, these terms are fully defined in the text of the report, followed by the abbreviation in the parenthesis. Subsequent references use the abbreviation only.

Abbreviation	Definition
A.F.	As-Fired
AQCS	Air Quality Control System
BA	Bed Ash
BOP	Balance of Plant
btu	British Thermal Unit
C	Coal
$CaCO_3$	wt. fraction $CaCO_3$ in limestone
Ca:S	Calcium to Sulfur Ration
CaO	Lime
C_b	Pounds of carbon per pound of “as-fired” fuel
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COMS	Continuous Opacity Monitoring System
DAHS	Data Acquisition Handling System
DCS	Distributed Control System
DOE	Department of Energy
F	Fluorine or Degrees Fahrenheit
FA	Fly ash
FF	Fabric Filter
gpm	gallons per minute
gr/acf	grains per actual cubic foot

Abbreviation	Definition
gr/dscf	grains per dry standard cubic foot
$h_{\#1DRN}$	Enthalpy of drain from #1 heater
$h_{\#1INFW}$	BFW enthalpy at heater #1 inlet
$h_{\#1OUTFW}$	BFW enthalpy at heater #1 outlet
H_{EXTR1}	Enthalpy of extraction to #1 heater
Hg	Mercury
HHV	Higher Heating Value
HP	High-Pressure
H_{CRH}	Cold reheat steam enthalpy at the boiler outlet, Btu/lb
h_{FW}	Feedwater enthalpy entering the economizer, Btu/lb
H_{HRH}	Hot reheat steam enthalpy at the boiler outlet, Btu/lb
H_{MS}	Main steam enthalpy at the boiler outlet, Btu/lb
L	Lime
lb/hr	Pounds per hour
lb/MMBtu	pounds per million Btu
LS	Limestone
MBtu	Million Btu
MCR	Maximum Continuous Rating
$MgCO_3$	wt. fraction $MgCO_3$ in limestone
MU	Measurement Uncertainty
MW_X	Molecular weight of respective elements
NGS	Northside Generating Station
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NS	Northside
Pb	Lead

Abbreviation	Definition
PC	Petroleum Coke
pcf	pounds per cubic foot
Pitt 8	Pittsburgh 8
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
ppm	parts per million
ppmdv	Pounds per million, dry volume
psia	Pounds per square inch pressure absolute
psig	pounds per square inch pressure gauge
PTC	Power Test Code
RH	Reheat
S $Capture_{(AQCS)}$	Sulfur capture by the AQCS, %
SDA	Spray Dryer Absorber
S_f	Wt. fraction of sulfur in fuel, as-fired
SH	Superheat
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
$SO_{2(inlet)}$	SO_2 in the AQCS inlet (lb/MBtu)
$SO_{2(stack)}$	SO_2 in the stack (lb/MBtu)
SO_3	Sulfur Trioxide
TG	Turbine Generator
tph	tons per hour
VOC	Volatile Organic Carbon
W_l	Limestone feed rate (lb/hr)
W_{EXTR1}	Extraction flow to heater #1
W_{fe}	Fuel feed rate (lb/hr)

Abbreviation	Definition
W_{FWH}	feedwater flow at heaters
W_{MS}	Main steam flow, lb/hr
W_{RH}	Reheat steam flow, lb/hr
wt %	weight percentage

JEA Tag Number Conventions are as follows:

AA-BB-CC-xxx

AA designates GEMS Group/System, as follows:

BK = Boiler Vent and Drains
QF = Feedwater Flow
SE = Reheat Piping
SH = Reheat Superheating
SI = Secondary Superheating
SJ = Main Street Piping

BB designates major equipment codes, as follows:

12 = Control Valve
14 = Manual Valve
34 = Instrument

CC designates instrument type, as follows:

FT = Flow transmitter
FI = Flow indicator
TE = Temperature element

xxx designates numerical sequence number

2.0 SUMMARY OF TEST RESULTS

2.1 Test Requirements

The Protocol required that the following tests be performed and the results be reported at four (4) different unit loads:

- Unit Capacity, per cent (all capacities in Megawatts are gross MW).
- Boiler Efficiency, per cent (100 % load only).
- Main Steam and Reheat Steam Temperature, deg F.
- Emissions (NOx, SO2, CO, and Particulate (see Section 4.0 of this report).

No design performance data for the boiler firing the blended fuel were provided by Foster-Wheeler. For the purposes of this report, the results of the test were compared against the design performance data of the boiler produced by Foster-Wheeler, as follows:

Boiler efficiency (firing Pittsburgh 8 coal):	88.1 % HHV
Boiler efficiency (firing Pet Coke):	90.0 % HHV
Main steam flow at turbine inlet:	1,993,591 lb/hr
Main steam temperature at turbine inlet:	1,000 deg F
Main steam pressure at turbine inlet:	2,500 psig
Hot reheat steam temperature at turbine inlet:	1,000 deg F

The average steam temperatures during the Test were compared with the limits described in the following sections (The average of the readings recorded every minute shall be determined to be the Test average):

a. Main steam temperature 1000 °F +10/-0 °F at the turbine throttle valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine throttle valve inlet from 60 to 75% of turbine MCR.

b. Hot reheat steam temperature 1000 °F +10/-0 °F at the turbine intercept valve inlet from 75 to 100% of turbine MCR and 1000 °F +/-10 °F at the turbine intercept valve inlet from 60 to 75% of turbine MCR.

2.2 Valve Line-Up Requirements

With the exception of isolating the blow down systems, drain and vent systems, and the soot blower system, the boiler was operated normally in the coordinated control mode throughout the boiler efficiency test period. Prior to the start of each testing period, a walk down was conducted to confirm the 'closed' position of certain main steam and feedwater system valves. A listing of these valves is included in Attachment F.

2.3 Test Results

The results of the 100% tests are summarized in Table 1. The boiler and SDA SO2 removal efficiencies are summarized in Table 2. The results of the part-load tests are summarized in Table 3. The performance of the boiler with regards to main steam flow, main steam temperature, and main steam pressure fell short of the design values provided by Foster-Wheeler. This performance short fall, however, did not prevent the turbine from providing the required megawatt output. It should be noted that the main steam temperature was controlled to a value below 950 deg F, as there were some stress issues with the superheater. The hot reheat temperature into the steam turbine met the design values provided by Foster-Wheeler.

Just after the start of the first 100% load test, the B1 feeder tripped. The decision was made to leave the feeder out of service and continue with the test. At the start of the 80% MCR test, the E1 feeder tripped. The test was completed with the E1 feeder out of service once the unit was stabilized. No further problems with the fuel feeding system were observed or recorded during the remainder of the part-load testing periods.

TABLE 1 - TESTS RESULTS - 100% LOAD

	Design Maximum-Continuous Rating (MCR)	August 10, 2004 Test (**corrected to MCR, see Note 4)	August 11, 2004 Test (**corrected to MCR, see Note 4)
Boiler Efficiency (percent)	88.1 (Coal) 90.0 (Pet Coke)	91.5 ** (Note 1)	91.6 ** (Note 1)
Capacity Calculation (percent)	NA	95.6	96.05
Main Steam (Turbine Inlet)			
Flow (lb/hr)	1,993,591	1,901,483 **	1,910,388 **
Pressure (psig)	2,500	2,401	2,401
Temperature (°F)	1,000	914.5 **	912.4 **
Reheat Steam (Turbine Inlet)			
Flow (lb/hr)	1,773,263	1,715,491	1,723,401
Pressure (psig)	547.7	592.6	590.8
Temperature (°F)	1,000	1,001.4 **	1,000.8 **
Reheat Steam (HP Turbine Exhaust)			
Flow (lb/hr)	1,773,263	1,715,448	1,723,361
Pressure (psig)	608.6	593.5	591.6
Enthalpy (Btu/lb)	1,304.5	1,290.1	1,289.97
Feedwater to Economizer			
Temperature (°F)	487.5	420.0	419.9
80/20 Blend Fuel Analysis (As-Received)			
Carbon %	73.8	81.36	82.14
Hydrogen %	4.1	3.63	3.67
Sulfur %	5.0	3.7	3.74
Nitrogen %	1.15	1.93	1.95
Chlorine %	0.05	0.03	0.03
Oxygen %	2.20	1.72	0.89
Ash %	6.6	2.33	2.41
Moisture %	7.1	5.34	5.20
HHV (Btu/lb)	13,345	14,085	14,081
Fuel Flow Rate (lb/hr)	NA	186,885	186,982
Limestone Composition (% By Weight)			
CaCO3	92.0	97.55	97.23
MgCO3	3.0	1.18	1.16
Inerts	4.0	1.27	1.61
Total Moisture	1.0	0.3	0.29

	Design Maximum-Continuous Rating (MCR)	August 10, 2004 Test (**corrected to MCR, see Note 4)	August 11, 2004 Test (**corrected to MCR, see Note 4)
AQCS Lime Slurry Composition (% By Weight)			
CaO (See Note 5)	85.0	46.24	46.24
MgO and inerts (See Note 5)	15.0	53.76	53.76
AQCS Lime Slurry Density – % Solids	35	1.25	1.41
Boiler Limestone Feedrate, lb/hr	66,056 (maximum value)	50,892	50,405
Flue Gas Emissions			
Nitrogen Oxides, NOx, lb/MMBtu (HHV)	0.09	0.0127	0.0081
Uncontrolled SO2, lb/MMBtu (HHV) - based on 80/20 blend	7.49	5.25	5.312
Boiler Outlet SO2, lb/MMBtu (HHV) [See Note 3]	0.78	0.1150	0.1636
Stack SO2 lb/MMBtu, (HHV)	0.15	0.058	0.07
Solid Particulate matter, baghouse outlet, lb/MMBtu (HHV)	0.011	0.0024	
Carbon Monoxide, CO, lb/MMBtu (HHV)	0.22	0.0127	0.0081
Opacity, percent	10	0.07	0.08
Ammonia (NH3) Slip, ppmvd	2.0	0.27	
Ammonia feed rate, gal/hr	NA	3.42	1.09
Lead, lb/MMBtu	2.60×10^{-5} (max)	4.424×10^{-7}	
Mercury (fuel and limestone), μg/g	NA	0.05	
Mercury, lb/TBtu (at stack)	10.5 (max)	< 0.07385	
Total Mercury Removal Efficiency, percent	No requirement	98 (See Note 2)	
Fluoride (as HF), lb/MMBtu	1.57×10^{-4} (max)	$< 5.3 \times 10^{-6}$	
Dioxins / Furans	No Limit	NOT TESTED	

NOTE 1: Boiler efficiency includes a value of 0.112 % for unaccounted for losses (from Foster-Wheeler data).
NOTE 2: Refer to Section 4.3.4.1.
NOTE 3: Design boiler outlet SO2 emission rate based on 85% removal of SO2 in the boiler.
NOTE 4: Corrections to design MCR conditions were made in accordance with Section 6.2.1 of Attachment A, FUEL CAPABILITY DEMONSTRATION TEST PROTOCOL.
NOTE 5: These components were not captured for this test - average results from Test #1 and Test #2 are indicated.

TABLE 2 - BOILER & SDA SO2 REMOVAL EFFICIENCY

	Design Basis	August 10, 2004 Test	August 11, 2004 Test)
Percent of total SO2 removed by boiler	85.0 typical, with range of 75 - 90	97.8	96.9
Percent of total SO2 removed by SDA	12.1 typical, with range 22.1 – 7.1	1.1	1.8
Percent of Total SO2 Removed	97.1	98.9	98.7
Percent of SO2 entering SDA removed in SDA	81.0 typical with range 90 – 71	49.5	57.0
Boiler Calcium to Sulfur Ratio	< 2.88	2.29	2.29

TABLE 3 - TEST RESULTS - PARTIAL LOADS (See Note 1)

	Aug. 12	Aug. 13
Unit Capacity (MW)	240	180
Percent MCR Load	80%	60%
Capacity Calculation (percent)	76.51	54.69
Total Main Steam Flow, lb/hr	1,393,557	1,021,784
Main Steam Temperature, deg F	980.55	980.62
Main Steam Pressure, psig	2,200.14	1,450.21
Cold Reheat Steam Temperature, deg F	579.46	595.45
Hot Reheat Steam Temperature, deg F	984.03	992.10
NOx, lb/MMBtu	0.027	0.018
CO, lb/MMBtu	0.0147	0.0218
SO2, lb/MMBtu	0.054	0.058
Opacity, percent	1	1

NOTE 1:
Test at 120 MW (40% load) cancelled due to Hurricane Charlie.

2.3.1 Unit Capacity - During the four (4) day testing period, the boiler was successfully operated at approximately 96% turbine load for day 1 and day 2 and at partial turbine loads of approximately 240 MW and 180 MW for day 3 and day 4. The load limitations during day 1 and day 2 were due to main steam temperature limitations to minimize stresses in the superheater tubes in the Intrex. The unit operated steadily at each of the stated loads without any deviation in unit output. Prior to each of the testing periods, the unit was brought to load and allowed to stabilize for two (2) hours prior to the start of each test.

2.3.2 Boiler Efficiency - The steam generator operated at corrected efficiencies of 91.5 % and 91.6% on Day 1 and Day 2, respectively, of the testing period.

2.3.3 Steam Temperature - During both days at 100% load operation, the average corrected main steam temperature measured at the turbine inlet was 913.5 deg F, which is significantly outside the design tolerances of the unit. The turbine generator output correction for an initial main steam temperature reduction of 86.5 F would be a reduction of about 1.8 MW. Additionally, the corrected hot reheat steam temperature measured at the turbine inlet was 1,001.1 deg F, which is within the design tolerances of the unit. During partial load operation, the main steam temperatures and the hot reheat temperatures were outside the design tolerances previously listed in Section 2.1.

2.3.4 Steam Production - The steam flows of the unit at the 100% load operation cases and partial load operation cases were each determined by adding the main steam desuperheating system flow rates to the feed water system flow rates, and subtracting the continuous blow down flow rates and the sootblowing steam flow rates. The data for each of these systems were retrieved from the plant information system database. The main steam flow rates were corrected for deviations from the design MCR feedwater temperature. Although the corrected main steam flow rates determined for the 100% load operation cases were less than the design flow rates established by Foster-Wheeler, the main steam flow rates were adequate to maintain the steam turbine at near the desired plant output. The primary reason plant output could be maintained is that the Foster Wheeler design flow rates included an approximately 2.5% design margin on main steam flow above that required by the turbine generator, to compensate for plant performance degradation over time. The main steam flow rates at the partial load operation cases were adequate to maintain the steam turbine at the required output.

2.3.5 Calcium to Sulfur Ratio (Ca:S) - The calcium to sulfur ratio represents the ability of the CFB boiler and limestone feed system to effectively remove the sulfur dioxide produced by the combustion process of the boiler. The maximum ratio established for firing the blend was 2.88. The calculated calcium to sulfur ratios for both Day 1 and Day 2 are 2.29. This value represents SO2 removal efficiencies for the boiler of greater than 95 % which are acceptable values for a CFB. SO2 reductions of greater than 90% are typically achieved in a CFB with Ca:S ratios of 2 to 2.5. These values are dependent on the sulfur content in the fuel and the reactivity of the limestone.

3.0 BOILER EFFICIENCY TESTS

The unit was operated at a steady turbine load of approximately 300 MW (100% MCR) for two (2) consecutive days as prescribed in Section 2 of the Attachment A Test Protocol. During these two days, data were recorded via the PI (Plant Information) System and were also collected by independent testing contractors. These data were then used to determine the unit's boiler efficiency. No significant operational restrictions were observed during testing at the 100% MCR condition.

3.1 Calculation Method

The boiler efficiency calculation method was based on a combination of the abbreviated heat loss method as defined in the ASME Power Test Code (PTC) 4.1, 1974, reaffirmed 1991, and the methods described in ASME PTC 4. The method was modified to account for the heat of calcination and sulfation within the CFB boiler SO2 capture mechanism. The methods have also been modified to account for process differences between conventional and fluidized bed boilers to account for the addition of limestone. These modifications account for difference in the dry gas quantity and the additional heat loss/gain due to calcinations / sulfation. A complete description of the modified procedures is included in Section 4.2 of Attachment A. Some of the heat losses included losses due to the heat in dry flue gas, unburned carbon in the bed ash and the fly ash, and the heat loss due to radiation and convection from the insulated boiler surfaces. A complete list of the heat losses can be found in Section 4.2.1 of Attachment A. The completed efficiency calculations are included in Attachment F to this report.

3.2 Data and Sample Acquisition

During the tests, permanently installed plant instrumentation was used to measure most of the data which were required to perform the boiler efficiency calculations. The data were collected electronically utilizing JEA's Plant Information (PI) system. The data provided by the plant instrumentation is included in *Attachment D, PI Data Summary*. Additional data required for the boiler efficiency calculations were provided by two independent testing contractors, PGT/ESC, and Clean Air Engineering (CAE). A summary of this information is located in *Attachments G, H, I, J, and K, lab analyses provided by PGT/ESC for the fuel, limestone, bed ash, fly ash, and environmental data,* and *Attachment C, CAE Test Report,* respectively. As directed in the test protocol (Attachment A), test data for days 1 and 2 were taken and labeled by CAE and PGT. No flue gas sampling was performed on the unit during operations at reduced loads. Data were, however, recorded by the CEMS system and are reported in this document.

The majority of the data utilized in the boiler efficiency calculation and sulfur capture performance, such as combustion air and flue gas temperatures and flue gas oxygen content, were stored and retrieved by the plant information system, as noted above. Data for the as-fired fuel, limestone, and resulting bed ash, fly ash, and exiting flue gas constituents were provided via laboratory analyses. Samples were taken in the following locations by PGT and forwarded to a lab for analysis. (Refer to Figures 1 thru 6 for approximate locations).

<u>Lime (Figure 1):</u>

Lime slurry samples were taken from the sample valve located on the discharge of the lime slurry transfer pump. This valve is located in the AQCS Spray Dryer Absorber (SDA) pump room.

<u>Fly Ash (Figures 2, 3, and 4):</u>

Fly Ash samples were taken by two different methods.

1) Fly ash was taken by isokinetic sampling at the inlet to the SDA. These samples were taken to determine ash loading rates and also obtain samples for laboratory analysis of ash constituents.
2) Fly ash was also taken by grab sample method in two different locations. One grab sample was taken every hour at a single air heater outlet hopper and another grab sample at a single bag house fabric filter hopper.

<u>Fuel (Figures 4, 5, and 6):</u>

Fuel samples were taken from the sample port at the discharge end of each gravimetric fuel feeder. The fuel samples were collected using a coal scoop inserted through the 4 inch test port at each operating fuel conveyor.

<u>Limestone (Figures 4 and 6):</u>

Limestone samples were taken from the outlet of each operating limestone rotary feeder. The samples were collected using a scoop passed into the flow stream of the 4 inch test ball valve in the neck of each feeder outlet.

<u>Bed Ash (Figure 6):</u>

Bed Ash samples were taken from each of the operating stripper cooler rotary valve outlets. The samples were taken by passing a stainless steel scoop through the 4 inch test port at each operating stripper cooler.

As instructed by the Test Protocol, all of the samples were labeled and transferred to a lab for analysis. The average values were determined and used as input data for performing the boiler efficiency calculation. The results of the lab analyses are included in Attachments G, H, I, and J.

4.0 AQCS INLET AND STACK TESTS

4.1 System Description

The Unit 2 AQCS consists of a single, lime-based spray dryer absorber (SDA) and a multi-compartment pulse jet fabric filter (PJFF). The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The AQCS system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [Ca(OH)2] slurry, which is fed to the atomizers as a supplemental reagent.

4.2 Unit Emissions Design Points

The following sections describe the desired emissions design goals of the unit. The tests were conducted in accordance with standard emissions testing practices and test methods as listed in Section 4.2.7. It should be noted that not all tests conducted fit exactly the 4 hour performance test period that was the basis of the fuel capability demonstration test. Several of the tests (especially those not based on CEMS) had durations that were different than the 4 hour performance period due to the requirements of the testing method and good engineering/testing practice. All sampling tests were done at the 100% load case only. All data at the 100%, 80%, and 60% performance load tests were collected by the CEMS (as previously stated the 40% partial load test was cancelled.).

4.3 Emission Design Limits and Results

4.3.1 NOx / SO2 / Particulate Emission Design Limits / Results

The following gaseous emissions were measured for each 4-hour interval during the Test (EPA Permit averaging period).

a. **Nitrogen oxides** (NOx) values in the flue gas as measured in the stack were expected to be less than 0.09 lb/MMBtu HHV fuel heat input. The hourly average lb/MMBtu values reported by the Continuous Emissions Monitoring system (CEMS) were used as the measure of NOx in the flue gas over the course of each fuel test. The average NOx values for Day 1 and Day 2, based on HHV, were 0.0127 lb/MMBtu and 0.0081 lb/MMBtu, respectively. Both of these values were less than the expected maximum value because the ammonia feed rate exceeded what was required to control emissions to the permitted level.

b. **Sulfur dioxide** (SO2) The design operating condition of the unit is to remove 85 percent of the SO2 in the boiler, with the balance to make the permitted emission rate removed in the SDA. Burning performance coal with a boiler SO2 removal efficiency of 85%, the SO2 concentration at the air heater outlet was expected to be 1.12 lb/MMBtu, with an uncontrolled SO2 emission rate (at 0% SO2 removal) calculated to be 7.49 lb/MMBtu. JEA has chosen to operate at a much higher boiler SO2 removal rate than design. Part of the reason for this operating mode is that reliability of the limestone feed system during and after the startup period was inadequate, resulting in a substantial number of periods with excess SO2 emissions. Over time the operations group has learned that if limestone feed is higher than normally desired the likelihood of excess emissions during an upset is reduced. Additionally, control of the AQCS slurry density at the desired density levels has been difficult due to some instrumentation and control issues that are not completely resolved yet. Modifications to increase the reliability and consistency of limestone feed are scheduled to be complete in late 2005, which should permit a change toward lower boiler SO2 removal and increased SDA removal.

The SO2 concentration at the SDA inlet was measured by an independent test contractor, Clean Air Engineering (CAE). These results are included in Attachment C. The average SO2 values for Day 1 and Day 2, based on HHV of the fuel, out of the air heaters and into the SDA, were 0.115 lb/MMBtu and 0.1636 lb/MMBtu, respectively. Both of these values were below the expected outlet emission rate. In fact, the boiler removed 97.8% and 96.9% respectively, in comparison to the design removal rate of 85%. Uncontrolled SO2 emissions rates were calculated to be 5.25 lb/MMBtu and 5.31 lb/MMBtu, respectively, for a decreased SO2 input of 29.9% and 29.1% below the design performance coal SO2 input of 7.49 lb/MMBtu.

The SO2 emissions from the stack during the execution of the tests were expected to be less than 0.15 lb/MMBtu. The hourly average lb/MMBtu values (based on HHV of the fuel) reported by CEMS were used as the measure of SO2 emissions from the stack for the test. The average SO2 values for Day 1 and Day 2, (based on HHV of the fuel) were 0.058 lb/MMBtu and 0.07 lb/MMBtu, respectively. These values were 61% and 53% lower than the 0.15 lb/MMBtu permitted emission rate. The SO2 emissions were substantially lower than required by permit because the limestone feed exceeded the amount required to control SO2 emissions to the required level.

c. **Solid particulate matter** in the flue gas at the fabric filter outlet was expected to be maintained at less than 0.011 lb/MMBtu HHV fuel heat input. These values were measured at the stack by CAE. The average particulate matter value for the testing period was 0.0024 lb/MMBtu which is below the expected maximum value.

4.3.2 CO Emissions Design Point

Carbon monoxide (CO) in the flue gas was expected to be less than or equal to 0.22 lb/MMBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by the plant CEMS. The average values for Day 1 and Day 2 were 0.0127 lb/MMBtu and 0.0081 lb/MMBtu, respectively. The average values were less than the maximum expected value.

4.3.3 SO3 Emissions Design Point

Sulfur Trioxide (SO3) in the flue gas was assumed to be zero due to the high removal efficiency of the SDA. No testing was done for SO3 as explained in the Test Protocol located in Attachment A. See Section 4.2.3 of the Fuel Capability Test Protocol for the rationale.

4.3.4 NH3/ Lead/ Mercury/ Fluorine Emissions Design Points

NH3, Lead, Mercury, and Fluorine gaseous emissions were measured during the Test (EPA Permit averaging period). Mercury sampling and analysis was performed at the inlet to the AQCS system in addition to the samples taken at the stack. Both samples were taken by CAE. Lead, ammonia and Fluorine were sampled only at the stack by CAE. The average values are indicated in Table 1.

4.3.4.1 Mercury Removal

Mercury in the flue gas was expected to be less than or equal to 10.5 lb/TBtu HHV fuel heat input at 100% MCR. This sample was measured at the stack by CAE, an independent testing contractor. The average values for the test were 0.07385 lb/TBtu. The average values were less than the maximum expected value. The inlet to SDA/FF for the test was 3.373 lb/TBtu which resulted in a 98 percent removal efficiency. The mercury test was conducted utilizing the Ontario Hydro Test Method. The Ontario Hydro mercury speciation results are detailed in Attachment C.

4.3.5 Dioxin and Furan Emissions Design Points

Dioxin and Furan gaseous emissions testing were not required for evaluation of the blend.

4.3.6 Opacity

The opacity was measured by the plant CEMS/COMS (Continuous Opacity Monitoring System) to determine the opacity of the unit over a six minute block average during the test period. The maximum expected opacity was 10%. The testing indicated that the maximum opacity of the unit during the two day test was 0.08%, which is much less than the maximum opacity value of 10%.

4.4 Flue Gas Emissions Test Methods

The emissions test methods used for the demonstration test were based upon utilizing 40 CFR 60 based testing methods or the plant CEMS. The emissions tests were conducted by CAE. The following test methods were utilized:

- Particulate Matter at SDA Inlet – USEPA Method 17
- Particulate Matter at Stack – USEPA Method 5
- Oxides of Nitrogen at Stack – Plant CEMS
- Sulfur Dioxide at SDA Inlet – USEPA Method 6C
- Sulfur Dioxide at Stack – Plant CEMS
- Carbon Monoxide at Stack – Plant CEMS
- Ammonia at Stack – CTM 027
- Lead at Stack – USEPA Method 29
- Mercury at SDA Inlet – Ontario Hydro Method
- Fluorine at Stack – USEPA Method 13B
- Dioxin/Furans – PCDD/F

Specific descriptions of the testing methods (non-CEMS) are included in the Clean Air Engineering Emissions Test Report located in Attachment D of this document.

4.5 Continuous Emission Monitoring System

The plant CEMS was utilized for measurement of gaseous emissions as a part of the fuel capability demonstration and as listed in Section 4.2.7. The CEMS equipment was integrated by KVB-Entertec (now GE Energy Systems). The system is a dilution extractive system consisting of Thermo Environmental NOX, SO2, and CO2 analyzers. The data listed for CEMS in Section 4.2.7 originated from the certified Data Acquisition Handling System (DAHS).

Attachments

ATTACHMENT A

Fuel Capability Demonstration Test Protocol

This Document is located via the following link:

http://www.netl.doe.gov/cctc/resources/pdfs/jacks/FCTP.pdf

ATTACHMENT B

Boiler Efficiency Calculation

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2**	**Boiler Efficiency:**	**91.90**
Test Date:	**August 10, 2004**		
Test Start Time:	**9:30 AM**		
Test End Time:	**1:30 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED		
		Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	186,885	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.8175	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0365	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0130	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0194	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0372	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0237	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0527	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	14,083	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	50,892	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9739	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0117	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0144	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0030	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.9875		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	277	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0064	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0064	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.0006	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	24,241	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0050	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0050	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.0168	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	24,416	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	103	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	20	LB/HR	
1.5.4	Fan Outlet Temperature, °F	103	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	1,438,159	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	99	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	42,094	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	185	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	42,116	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	205	°F	tspb

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2
Test Date:	August 10, 2004
Test Start Time:	9:30 AM
Test End Time:	1:30 PM
Test Duration, hours:	4

Boiler Efficiency: 91.90

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	86.19	°F	ta
1.6.2	Ambient wet bulb temperature, °F	72.19	°F	tawb
1.6.3	Barometric pressure, inches Hg	30.15	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0137	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	289.30	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0466	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	526.82	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0022	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	2443.3	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	420.2	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,754,223	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	1,253.9	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	574.3	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,693.3	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	279.7	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	27,026	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.7	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	980.3	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,781,249	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	933.66	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	312.94	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	43	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	593.52	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	599.45	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	592.57	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	989.23	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,715,448	LB/HR	RHin - From turbine heat.

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2**	**Boiler Efficiency:**	**91.90**
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Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 102.59

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1	ASSUMED FUEL FLOW RATE, lb/h	174,084	lb/h	
3.2	ASSUMED SULFUR EMISSIONS, fraction	0.0446	fraction	Can get reading from CEMS system
3.3	Sulfur Capture, fraction	0.9554		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1	**Accumulation of Bed Inventory**	0	lb/h	
4.2	**Corrected Ash Carbon Content**			
4.2.1	Bottom Ash, fraction	0.0064	lb/lb BA	
4.2.2	Fly Ash, fraction	0.0050	lb/lb FA	
4.3	**Bottom Ash Flow Rate**			
4.3.1	Total bottom ash including bed change	24,240.8178660	lb/h	
4.4	**Limestone Flow Rate**			

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	2.4496	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.869494842	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	50892	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	2.449545967	mole Ca/mole S	
	Limestone Flow Rate from PI Data, lb/hr	**50,892**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-0.000207975	percent	
4.4.6	Calculated Fly Ash Flow Rate	24,416	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000005)	percent	
4.5	**Total Dry Refuse**			
4.5.1	Total Dry Refuse Hourly Flow Rate	48,657	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.2795	lb/lb AF fuel	
4.6	**Heating Value Of Total Dry Refuse**			
4.6.1	Average Carbon Content Of Ash	0.0057	fraction	
4.6.2	Heating Value Of Dry Refuse	82.61	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1	**Carbon Burned Adjusted For Limestone**		
5.1.1	Carbon Burned	0.8159	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.8501	lb/lb AF fuel

Jacksonville Electric Authority

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Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	28.952	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.4964	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	8.2918	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	3.1149	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0033	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.7050	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	10.6924	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0194	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0527	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3263	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0009	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.1903	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	14.5350	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.7137	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	15.1051	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.9178	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.9558	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0109	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.6555	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.2316	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1460	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.655555556	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	0.000276621	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1496		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8039		
5.2.14	Weight Dry FG At Air Heater OUTLET	14.4778	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.7118	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	14.0184	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01026	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.3637	percent volume	
5.2.16.4	Nitrogen from air, volume percent	75.2030	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1369	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.2677	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	15.0479	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.9132	lb/lb mole	

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0485	fraction
5.2.19.2	Nitrogen, fraction weight	0.7371	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2144	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.220	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	3.1149	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0033	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5120	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	10.0513	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0194	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0527	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3263	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0009	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.1789	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	13.7009	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.8270	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	14.2596	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.9914	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.9249	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	80.3080	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1555	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-0.00035125	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1592	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8025	
5.3.12	Weight Dry FG At Air Heater INLET	13.6886	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.9002	lb/lb mole

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Unit Tested:	**Northside Unit 2**	**Boiler Efficiency:**	**91.90**
Test Date:	**August 10, 2004**		
Test Start Time:	**9:30 AM**		
Test End Time:	**1:30 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		Volume Basis % Wet Flue Gas	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas		
5.3.14.1	Carbon Dioxide, volume percent	14.8862	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01090	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3652	percent volume
5.3.14.4	Nitrogen from air, volume percent	75.0699	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1454	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.5224	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	14.2473	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	30.0573	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0373	fraction
5.3.17.2	Nitrogen, fraction weight	0.7314	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2267	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0046	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0358	fraction
5.3.18.2	Nitrogen, fraction weight	0.7027	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2180	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0044	fraction
5.3.18.6	Moisture, fraction weight	0.0391	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	22.956	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	3.1149	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0033	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5553	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	10.1953	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0194	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0527	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3263	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0009	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.1814	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	13.8881	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.8003	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	14.4494	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.9741	lb/lb mole

		Volume Basis % Wet Flue Gas	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas		
5.4.7.1 a	Carbon Dioxide, volume percent	14.6822	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	75.1012	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1434	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.4625	percent volume
		100.0000	percent volume

Boiler Efficiency: 91.90

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		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.6966	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8487	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	80.2900	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1533	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume

5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet l	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	0.000386937	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-0.000113237	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

	Oxygen
C0	-1.1891960E+02
C1	4.2295190E-01
C2	-1.6897910E-04
C3	3.7071740E-07
C4	-2.7439490E-10
C5	7.384742E-14

5.5.2 a	Flue Gas Constituent Enthalpy At tG15	4.722260E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8	5.620947E+00

	Nitrogen
C0	-1.3472300E+02
C1	4.6872240E-01
C2	-8.8993190E-05
C3	1.1982390E-07
C4	-3.7714980E-11
C5	-3.5026400E-16

5.5.2 b	Flue Gas Constituent Enthalpy At tG15	5.2407852E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8	6.3057036E+00

	Carbon Dioxide
C0	-8.5316190E+01
C1	1.9512780E-01
C2	3.5498060E-04
C3	-1.7900110E-07
C4	4.0682850E-11
C5	1.0285430E-17

5.5.2 c	Flue Gas Constituent Enthalpy At tG15	4.5667043E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8	5.2090748E+00

	Carbon Monoxide
C0	-1.3574040E+02
C1	4.7377220E-01
C2	-1.0337790E-04
C3	1.5716920E-07
C4	-6.4869650E-11
C5	6.1175980E-15

5.5.2 d	Flue Gas Constituent Enthalpy At tG15	5.2958326E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8	6.3611350E+00

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	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.3274763E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	3.8315902E+00		

General equation for constituent enthalpy:
$h = C0 + C1 * T + C2 * T^2 + C3 * T^3 + C4 * T * T^3 + C5 * T^2 * T^3$
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	50.71	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	6.04	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	646.78	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	4.59	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1190.75	Btu/lb	$hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)^2 + 1062.2 - PTC$
6.2	Saturated Water Enthalpy at tA8	70.59	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	58.99	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	0.42	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	365.48	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	2.60	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	23.09	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	0.16	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	6.06	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	5.24	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	11.30	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.08	percent

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10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	14.24	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	143.32	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	50.31	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	18.12	Btu/lb
10.3 HHV Percent Loss, as tested		0.13	percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	217.57	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	0.97	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-239.48	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-20.95	Btu/lb AF Fuel
11.5 HHV Percent Loss		-0.15	percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss		0.27	percent
12.1.1	Radiation & Convection Heat Loss	38.50	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	646.78
13.1.2	58.99
13.1.3	365.48
13.1.4	23.09
13.1.5	11.30
13.1.6	18.12
13.1.7	-20.95
13.1.8	38.50
	1,141.30

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		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.59
13.1.10	Moisture In Fuel	0.42
13.1.11	H2O From H2 In Fuel	2.60
13.1.12	Unburned Combustibles In Refuse	0.16
13.1.13	Dry Refuse	0.08
13.1.14	Moisture In Combustion Air	0.13
13.1.15	Calcination/Sulfation	-0.15
13.1.16	Radiation & Convection	0.27
		8.10

13.2 Boiler Efficiency (100 - Total Losses), percent 91.90

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	399.09	Btu/lb
14.1.2	Blow Down, Btu/lb	581.21	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	253.99	Btu/lb
14.1.5	Main Steam, Btu/lb	1447.96	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	284.50	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1288.73	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1510.64	Btu/lb

14.2 Heat Output 2,252,955,081 Btu/h

2,253,692,528

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,451,637,059	Btu/h
15.1.2	Fuel Burned - CALCULATED	174,084	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	3.88562E-05	percent

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Unit Tested: **Northside Unit 2**

Test Date: **August 11, 2004**

Test Start Time: **8:00 AM**

Test End Time: **12:00 PM**

Test Duration, hours: **4**

Boiler Efficiency: 92.00

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DATA INPUT SECTION - INPUT ALL DATA REQUESTED IN SECTION 1 EXCEPT AS NOTED

1. DATA REQUIRED FOR BOILER EFFICIENCY DETERMINATION

		AS - TESTED Average Value	Units	Symbol
1.1 Fuel				
1.1.1	Feed Rate, lb/h	186,982	lb/h	Wfe - Summation feeder feed rates - FN-34-FT-508, 528, 548, 568, 588, 608, 628, 668
	Composition ("as fired")			
1.1.2	Carbon, fraction	0.8175	lb/lb AF fuel	Cf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.3	Hydrogen, fraction	0.0365	lb/lb AF fuel	Hf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.4	Oxygen, fraction	0.0130	lb/lb AF fuel	Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.5	Nitrogen, fraction	0.0194	lb/lb AF fuel	Nf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.6	Sulfur, fraction	0.0372	lb/lb AF fuel	Sf - Laboratory analysis of coal samples obtained by grab sampling.
1.1.7	Ash, fraction	0.0237	lb/lb AF fuel	Af - Laboratory analysis of coal samples obtained by grab sampling.
1.1.8	Moisture, fraction	0.0527	lb/lb AF fuel	H2Of - Laboratory analysis of coal samples obtained by grab sampling.
1.1.9	Calcium, fraction	0.0000	lb/lb AF fuel	Caf - Laboratory analysis of coal samples obtained by grab sampling - assume a value of zero if not reported.
1.1.10	HHV	14,083	Btu/lb	HHV - Laboratory analysis of coal samples obtained by grab sampling.
1.2 Limestone				
1.2.1	Feed Rate, lb/h	50,405	lb/h	Wle - Summation feeder feed rates - 2RN-53-010-Rate, 011, 012
	Composition ("as fired")			
1.2.2	CaCO3, fraction	0.9739	lb/lb limestone	CaCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.3	MgCO3, fraction	0.0117	lb/lb limestone	MgCO3l - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.4	Inerts, fraction	0.0144	lb/lb limestone	Il - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.5	Moisture, fraction	0.0030	lb/lb limestone	H2Ol - Laboratory analysis of limestone samples obtained by grab sampling.
1.2.6	Carbonate Conversion, fraction	0.9875		XCO2 - Laboratory analysis of limestone samples obtained by grab sampling - assume value of 1 if not reportec
1.3 Bottom Ash				
1.3.1	Temperature, °F at envelope boundary	235	°F	tba - Plant instrument.
	Composition			
1.3.2	Organic Carbon, wt fraction	0.0064	lb/lb BA	Cbao - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.3	Inorganic Carbon, wt fraction	0.0000	lb/lb BA	Cbaio - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.4	Total Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0064	lb/lb BA	Cba = Cbao + Cbaio
1.3.5	Calcium, wt fraction	0.0006	lb/lb BA	Caba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.6	Carbonate as CO2, wt fraction	0.0000	lb/lb BA	CO2ba - Laboratory analysis of bottom ash samples obtained by grab sampling.
1.3.7	Bottom Ash Flow By Iterative Calculation - ENTER ASSUMED VALUE TO BEGIN CALCULATION	20,831	lb/h	Wbae
1.4 Fly Ash				
	Composition			
1.4.1	Organic Carbon, wt fraction	0.0050	lb/lb FA	Cfao - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.2	Inorganic Carbon, wt fraction	0.0000	lb/lb FA	Cfaio - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.3	Carbon, wt fraction - CALCULATED VALUE DO NOT ENTER	0.0050	lb/lb FA	Cfa = Cfao + Cfaio
1.4.4	Calcium, wt fraction	0.0168	lb/lb FA	Cafa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.5	Carbonate as CO2, wt fraction	0.0000	lb/lb FA	CO2fa - Laboratory analysis of fly ash samples obtained by grab sampling.
1.4.6	Fly Ash Flow	27,603	LB/HR	Wfam - Weight of fly ash from isokenetic sample collection.
1.5 Combustion Air				
	Primary Air			
	Hot			
1.5.1	Flow Rate, lb/h	1,761,691	lb/h	Wpae - Plant instrument.
1.5.2	Air Heater Inlet Temperature, °F	103	°F	tpa
	Cold			
1.5.3	Flow Rate, lb/h	23	LB/HR	
1.5.4	Fan Outlet Temperature, °F	103	°F	
	Secondary Air			
1.5.5	Flow Rate, lb/h	2,405,887	lb/h	Wsae - Plant instrument.
1.5.6	Air Heater Inlet Temperature, °F	99	°F	tsa
	Intrex Blower			
1.5.7	Flow Rate, lb/h	41,813	lb/h	Wib - Plant instrument
1.5.8	Blower Outlet Temperature, oF	182	°F	tib
	Seal Pot Blowers			
1.5.9	Flow Rate, lb/h	41,538	lb/h	Wspb - Plant instrument
1.5.10	Blower Outlet Temperature, oF	200	°F	tspb

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1.6 Ambient Conditions				
1.6.1	Ambient dry bulb temperature, °F	83.71	°F	ta
1.6.2	Ambient wet bulb temperature, °F	75.13	°F	tawb
1.6.3	Barometric pressure, inches Hg	29.99	inches Hg	Patm
1.6.4	Moisture in air, lbH2O/lb dry air	0.0169	lbH2O/lb dry air	Calculated: H2OA - From psychometric chart at temperatures ta and tawb adjusted to test Patm.
1.7 Flue Gas				
	At Air Heater Outlet			
1.7.1	Temperature (measured), °F	284.51	°F	Tg15 - Weighted average from AH outlet plant instruments (based on PA and SA flow rates) THIS MAY NEED
1.7.2	Temperature (unmeasured), °F			Calculated
	Composition (wet)			
1.7.3	O2	0.0466	percent volume	O2 - Weighted average from test instrument, may not have to weight depending on location of probes
1.7.4	CO2	Not Measured	percent volume	CO2
1.7.5	CO	Not Measured	percent volume	CO
1.7.6	SO2	Not Measured	percent volume	SO2
	At Air Heater Inlet			
1.7.7	Temperature, °F	523.22	°F	tG14 - Plant Instrument
	Composition (wet)			
1.7.8	O2	0.0360	percent volume	
1.7.9	CO2	Not Measured	percent volume	
1.7.10	CO	Not Measured	percent volume	
1.7.11	SO2	0.0030	percent volume	measurement is in ppm
	CEM Sample Extraction At Outlet Of Economizer			
	Composition			
1.7.12	O2, percent - WET basis	3.600	percent volume	O2stk
1.7.13	SO2, ppm - dry basis	114.9	ppm	SO2stk
1.7.14	NOx, ppm - dry basis	Not Measured	ppm	Noxstk
1.7.15	CO, ppm - dry basis	Not Measured	ppm	Costk
1.7.16	Particulate, mg/Nm³	Not Measured	mg/Nm³ - 25° C	PARTstk
1.8 Feedwater				
1.8.1	Pressure, PSIG	2443.9	PSIG	pfw - Plant instrument.
1.8.2	Temperature, °F	419.9	°F	tfw - Plant instrument.
1.8.3	Flow Rate, lb/h	1,770,064	lb/h	FW - Plant instrument.
1.9 Continuous Blow Down				
1.9.1	Pressure, PSIG (drum pressure)	1,242.6	PSIG	pbd - Plant instrument
1.9.2	Temperature, °F (sat. temp. @ drum pressure)	573.2	°F	tba - Saturated water temperature from steam table at drum pressure.
1.9.3	Flow Rate, lb/h	0.00	lb/h	BD - Estimated using flow characteristic of valve and number of turns open.
1.10 Sootblowing				
1.10.1	Flow Rate, LB/HR	0.00	LB/HR	SB - Plant instrument
1.10.2	Pressure, PSIG	0.00	PSIG	psb - Plant instrument
1.10.3	Temperature, F	0.00	F	tsb - plant instrument
1.11 Main Steam Desuperheating Water				
1.11.1	Pressure, PSIG	2,695.5	PSIG	pdsw - Plant instrument.
1.11.2	Temperature, °F	278.3	°F	tdsw - Plant instrument.
1.11.3	Flow Rate, lb/h	19,359	lb/h	DSW - Plant instrument.
1.12 Main Steam				
1.12.1	Pressure, PSIG (superheater outlet)	2,400.7	PSIG	pms - Plant instrument.
1.12.2	Temperature, °F	980.5	°F	tms - Plant instrument.
1.12.3	Flow Rate, lb/h	1,789,423	lb/h	MS - Plant instrument - Not required to determine boiler efficiency - For information only.
1.13 Reheat Steam Desuperheating Water				
1.13.1	Pressure, PSIG	933.76	PSIG	pdswrh - Plant instrument.
1.13.2	Temperature, °F	312.85	°F	tdswrh - Plant instrument.
1.13.3	Flow Rate, lb/h	40	lb/h	DSWrh - Plant instrument.
1.14 Reheat Steam				
1.14.1	Inlet Pressure, PSIG	591.57	PSIG	prhin - Plant instrument.
1.14.2	Inlet Temperature, °F	598.95	°F	trhin - Plant instrument.
1.14.3	Outlet Pressure, PSIG	590.78	PSIG	prhout - Plant instrument.
1.14.4	Outlet Temperature, °F	988.40	°F	trhout - Plant instrument.
1.14.5	Inlet Flow, LB/HR	1,723,361	LB/HR	RHin - From turbine heat.

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Test End Time:	**12:00 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

CALCULATION SECTION - ALL VALUES BELOW CALCULATED BY EMBEDDED FORMULAS - DO NOT ENTER DATA BELOW THIS LINE - EXCEPT ASSUMED VALUES FOR ITERATIVE CALCULATIONS

2. REFERENCE TEMPERATURES

2.1 Average Air Heater Inlet Temperature 101.63

3. SULFUR CAPTURE

The calculation of efficiency for a circulating fluid bed steam generator that includes injection of a reactive sorbent material, such as limestone, to reduce sulfur dioxide emissions is an iterative calculation to minimize the number of parameters that have to be measured and the number of laboratory material analyses that must be performed. This both reduces the cost of the test and increases the accuracy by minimizing the impact of field and laboratory instrument inaccuracies.

To begin the process, assume a fuel flow rate. The fuel flow rate is required to complete the material balances necessary to determine the amount of limestone used and the effect of the limestone reaction on the boiler efficiency. The resulting boiler efficiency is used to calculate a value for the fuel flow rate. If the calculated flow rate is more than 1 percent different than the assumed flow rate, a new value for fuel flow rate is selected and the efficiency calculation is repeated. This process is repeated until the assumed value for fuel flow and the calculated value for fuel flow differ by less than 1 percent of of the value of the calculated fuel flow rate.

3.1 ASSUMED FUEL FLOW RATE, lb/h		174,614	lb/h	
3.2 ASSUMED SULFUR EMISSIONS, fraction		0.0447	fraction	Can get reading from CEMS system
3.3 Sulfur Capture, fraction		0.9553		

4. ASH PRODUCTION AND LIMESTONE CONSUMPTION

4.1 Accumulation of Bed Inventory		0	lb/h	
4.2 Corrected Ash Carbon Content				
4.2.1	Bottom Ash, fraction	0.0064	lb/lb BA	
4.2.2	Fly Ash, fraction	0.0050	lb/lb FA	
4.3 Bottom Ash Flow Rate				
4.3.1	Total bottom ash including bed change	20,831.0554960	lb/h	
4.4 Limestone Flow Rate				

Iterate to determine calcium to sulfur ratio and limestone flow rate. Enter an assumed value for the calcium to sulfur ratio. Compare resulting calculated calcium to sulfur ratio to assumed value. Change assumed value until the difference between the assumed value and the calculated value is less than 1 percent of the assumed value.

4.4.1	ASSUMED CALCIUM to SULFUR RATIO	2.4187	mole Ca/mole S	
4.4.2	Solids From Limestone - estimated	0.873350139	lb/lb limestone	al = (CaCO3l * (56.0794/100.08935)) + ((CaCO3l/CaS) * (80.0622/100.08935) * XSO2) +
4.4.3	Limestone Flow Rate - estimated	50405	lb/h	Wle = ((Wfea * af * ((Caf - (Cafa/(1 - Cfai)))) + Wbae' * (1 - Cba') * ((Cafa/(1 - Cfa)) - Caba))/((Cafa/(1 -
4.4.4	Calculated Calcium to Sulfur Ratio	2.418739973	mole Ca/mole S	
	Limestone Flow Rate from PI Data, lb/hr	**50,405**		
4.4.5	Difference Estimated vs Assumed - Ca:S	-0.000111406	percent	
4.4.6	Calculated Fly Ash Flow Rate	27,603	lb/h	
4.4.7	Difference Calculated vs Measured	(0.0000000002)	percent	
4.5 Total Dry Refuse				
4.5.1	Total Dry Refuse Hourly Flow Rate	48,434	lb/h	
4.5.2	Total Dry Refuse Per Pound Fuel	0.2774	lb/lb AF fuel	
4.6 Heating Value Of Total Dry Refuse				
4.6.1	Average Carbon Content Of Ash	0.0056	fraction	
4.6.2	Heating Value Of Dry Refuse	81.23	Btu/lb	

5. HEAT LOSS DUE TO DRY GAS

5.1 Carbon Burned Adjusted For Limestone			
5.1.1	Carbon Burned	0.8159	lb/lb AF fuel
5.1.2	Carbon Adjusted For Limestone	0.8497	lb/lb AF fuel

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2**	**Boiler Efficiency:**	**92.00**
Test Date:	**August 11, 2004**		
Test Start Time:	**8:00 AM**		
Test End Time:	**12:00 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

Determine Amount Of Flue Gas

Iterate to determine carbon dioxide volumetric content of dry flue gas. Enter an assumed value for excess air.
Compare resulting calculated oxygen content to the measure oxygen content. Change assumed value of excess air until the difference between the calculated oxygen content value and the measured value oxygen content value is less than 1 percent of the assumed value.
Use the calculated carbon dioxide value in subsequent calculations.

5.2 Air Heater Outlet

5.2.1	ASSUMED EXCESS AIR at AIR HEATER **OUTLET**	28.949	percent	
5.2.2	Corrected Stoichiometric O2, lb/lb fuel	2.4965	lb/lb AF fuel	O2stoich = (31.9988/12.01115) * Cb + (15.9994/2.01594) * Hf + (31.9998/32.064) * Sf - Of + (((Sf * 31.9988/32.064) * (XSO2) * 31.9988 * 0.5/64.0128)
5.2.3	Corrected Stoichiometric N2, lb/lb fuel	8.2922	lb/lb AF fuel	
5.2.4	Flue Gas Composition, Weight Basis, lb/lb AF Fuel			
5.2.4.1	Carbon Dioxide, weight fraction	3.1135	lb/lb AF fuel	
5.2.4.2	Sulfur Dioxide, weight fraction	0.0033	lb/lb AF fuel	
5.2.4.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.7050	lb/lb AF fuel	
5.2.4.4	Nitrogen from air, weight fraction	10.6926	lb/lb AF fuel	
5.2.4.5	Nitrogen from fuel, weight fraction	0.0194	lb/lb AF fuel	
5.2.4.6	Moisture from fuel, weight fraction	0.0527	lb/lb AF fuel	
5.2.4.7	Moisture from hydrogen in fuel, weight fraction	0.3263	lb/lb AF fuel	
5.2.4.8	Moisture from limestone, weight fraction	0.0009	lb/lb AF fuel	
5.2.4.9	Moisture from combustion air, weight fraction	0.2346	lb/lb AF fuel	
5.2.5	Weight of DRY Products of Combustion - Air Heater OUTLET	14.5337	lb/lb AF fuel	
5.2.6	Molecular Weight, lb/lb mole DRY FG - Air Heater OUTLET	30.7128	lb/lb mole	MWahoutdry = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134))
5.2.7	Weight of WET Products of Combustion - Air Heater OUTLET	15.1481	lb/lb AF fuel	
5.2.8	Molecular Weight, lb/lb mole WET FG - Air Heater OUTLET	29.8592	lb/lb AF fuel	MWahoutwet = Wgcalc/((CO2calc/44.0095) + (SO2calc/64.0629) + (O2calc/31.9988) + (N2acalc/28.161) + (Nf/28.0134) + ((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534)) Note: Molecular weight of nitrogen in air (N2a) is 28.161 lb/lb mole per PTC 4 Sub-Section 5.11.1 to account for trace gases in air.
5.2.9	Dry Flue Gas Composition, Volume Basis, % Dry Flue Gas			
5.2.9.1	Carbon Dioxide, volume percent	14.9498	percent volume	
5.2.9.2	Sulfur Dioxide, volume percent	0.0110	percent volume	
5.2.9.3	Oxygen from air, volume percent	4.6555	percent volume	
5.2.9.4	Nitrogen from air, volume percent	80.2377	percent volume	
5.2.9.5	Nitrogen from fuel, volume percent	0.1460	percent volume	
		100.0000	percent volume	
5.2.10	Oxygen - MEASURED AT AIR HEATER OUTLET, % vol - dry FG	4.655555556	percent	
5.2.11	Difference Calculated versus Measured Oxygen At Air Heater Outlet	0.000302348	percent	
5.2.12	Carbon Dioxide, DRY vol. fraction	0.1495		
5.2.13	Nitrogen (by difference), DRY vol. fraction	0.8039		
5.2.14	Weight Dry FG At Air Heater OUTLET	14.4796	lb/lb AF fuel	
5.2.15	Molecular Weight Of Dry Flue Gas At Air Heater OUTLET	30.7092	lb/lb mole	
5.2.16	Wet Flue Gas Composition, Volume Basis, % Wet Flue Gas			
5.2.16.1	Carbon Dioxide, volume percent	13.9448	percent volume	
5.2.16.2	Sulfur Dioxide, volume percent	0.01022	percent volume	
5.2.16.3	Oxygen from air, volume percent	4.3426	percent volume	
5.2.16.4	Nitrogen from air, volume percent	74.8436	percent volume	
5.2.16.5	Nitrogen from fuel, volume percent	0.1362	percent volume	
5.2.16.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.7226	percent volume	H2O%out = (((H2Of + H2Oh2 + H2Ol/f + H2Oair)/18.01534) * (100)/(Wgcalcahoutwet/MWahoutwet)
		100.0000		
5.2.17	Weight Wet FG At Air Heater OUTLET	15.0940	lb/lb AF fuel	
5.2.18	Molecular Weight Of Wet Flue Gas At Air Heater OUTLET	29.8530	lb/lb mole	

Boiler Efficiency: 92.00

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

5.2.19	Weight Fraction of DRY Flue Gas Components		
5.2.19.1	Oxygen, fraction weight	0.0485	fraction
5.2.19.2	Nitrogen, fraction weight	0.7372	fraction
5.2.19.3	Carbon Dioxide, fraction weight	0.2143	fraction
5.2.19.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.2.19.5	Sulfur Dioxide, fraction weight	0.0000	fraction
5.2.20	Weight Fraction of WET Flue Gas Components -NOT USED IN CALCULATION		
5.2.20.1	Oxygen, fraction weight		fraction
5.2.20.2	Nitrogen, fraction weight		fraction
5.2.20.3	Carbon Dioxide, fraction weight		fraction
5.2.20.4	Carbon Monoxide, fraction weight		fraction
5.2.20.5	Sulfur Dioxide, fraction weight		fraction
5.2.20.6	Moisture, fraction weight		fraction

5.3 Air Heater Inlet

5.3.1	ASSUMED EXCESS AIR at AIR HEATER **INLET**	21.218	percent
5.3.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.3.2.1	Carbon Dioxide, weight fraction	3.1135	lb/lb AF fuel
5.3.2.2	Sulfur Dioxide, weight fraction	0.0033	lb/lb AF fuel
5.3.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5120	lb/lb AF fuel
5.3.2.4	Nitrogen from air, weight fraction	10.0516	lb/lb AF fuel
5.3.2.5	Nitrogen from fuel, weight fraction	0.0194	lb/lb AF fuel
5.3.2.6	Moisture from fuel, weight fraction	0.0527	lb/lb AF fuel
5.3.2.7	Moisture from hydrogen in fuel, weight fraction	0.3263	lb/lb AF fuel
5.3.2.8	Moisture from limestone, weight fraction	0.0009	lb/lb AF fuel
5.3.2.9	Moisture from combustion air, weight fraction	0.2206	lb/lb AF fuel
5.3.3	Weight of DRY Products of Combustion - Air Heater INLET	13.6997	lb/lb AF fuel
5.3.4	Molecular Weight, lb/lb mole DRY FG - Air Heater INLET	30.8260	lb/lb mole
5.3.5	Weight of WET Products of Combustion - Air Heater INLET	14.3000	lb/lb AF fuel
5.3.6	Molecular Weight, lb/lb mole WET FG - Air Heater INLET	29.9324	lb/lb AF fuel
5.3.7	Flue Gas Composition, Volume Basis, % DRY Flue Gas	Volume Basis % Dry Flue Gas	
5.3.7.1	Carbon Dioxide, volume percent	15.9184	percent volume
5.3.7.2	Sulfur Dioxide, volume percent	0.0117	percent volume
5.3.7.3	Oxygen from air, volume percent	3.6000	percent volume
5.3.7.4	Nitrogen from air, volume percent	80.3144	percent volume
5.3.7.5	Nitrogen from fuel, volume percent	0.1555	percent volume
		100.0000	percent volume
5.3.8	Oxygen - MEASURED AT AIR HEATER INLET, % vol - dry FG	3.6	percent
5.3.9	Difference Calculated versus Measured Oxygen At Air Heater Inlet	-0.000343849	percent
5.3.10	Carbon Dioxide, DRY vol. fraction	0.1592	
5.3.11	Nitrogen (by difference), DRY vol. fraction	0.8018	
5.3.12	Weight Dry FG At Air Heater INLET	13.6964	lb/lb AF fuel
5.3.13	Molecular Weight Of Dry Flue Gas At Air Heater INLET	30.9317	lb/lb mole

Boiler Efficiency: 92.00

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		Volume Basis	
5.3.14	Flue Gas Composition, Volume Basis, % Wet Flue Gas	% Wet Flue Gas	
5.3.14.1	Carbon Dioxide, volume percent	14.8081	percent volume
5.3.14.2	Sulfur Dioxide, volume percent	0.01086	percent volume
5.3.14.3	Oxygen from air, volume percent	3.3489	percent volume
5.3.14.4	Nitrogen from air, volume percent	74.7122	percent volume
5.3.14.5	Nitrogen from fuel, volume percent	0.1447	percent volume
5.3.14.6	Moisture from fuel, fuel hydrogen, limestone, and air	6.9753	percent volume
		100.0000	
5.3.15	Weight Wet FG At Air Heater INLET	14.2967	lb/lb AF fuel
5.3.16	Molecular Weight Of Wet Flue Gas At Air Heater INLET	30.0277	lb/lb mole
5.3.17	Weight Fraction of DRY Flue Gas Components		
5.3.17.1	Oxygen, fraction weight	0.0372	fraction
5.3.17.2	Nitrogen, fraction weight	0.7300	fraction
5.3.17.3	Carbon Dioxide, fraction weight	0.2265	fraction
5.3.17.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.17.5	Sulfur Dioxide, fraction weight	0.0063	fraction
5.3.18	Weight Fraction of WET Flue Gas Components		
5.3.18.1	Oxygen, fraction weight	0.0357	fraction
5.3.18.2	Nitrogen, fraction weight	0.6993	fraction
5.3.18.3	Carbon Dioxide, fraction weight	0.2170	fraction
5.3.18.4	Carbon Monoxide, fraction weight	0.0000	fraction
5.3.18.5	Sulfur Dioxide, fraction weight	0.0060	fraction
5.3.18.6	Moisture, fraction weight	0.0418	fraction

5.4 CEM Sampling Location

5.4.1	ASSUMED EXCESS AIR at **CEM** SAMPLING LOCATION	23.085	percent
5.4.2	Flue Gas Composition, Weight Basis, lb/lb AF Fuel		
5.4.2.1	Carbon Dioxide, weight fraction	3.1135	lb/lb AF fuel
5.4.2.2	Sulfur Dioxide, weight fraction	0.0033	lb/lb AF fuel
5.4.2.3	Oxygen from air less oxygen to sulfur capture, weight fraction	0.5586	lb/lb AF fuel
5.4.2.4	Nitrogen from air, weight fraction	10.2064	lb/lb AF fuel
5.4.2.5	Nitrogen from fuel, weight fraction	0.0194	lb/lb AF fuel
5.4.2.6	Moisture from fuel, weight fraction	0.0527	lb/lb AF fuel
5.4.2.7	Moisture from hydrogen in fuel, weight fraction	0.3263	lb/lb AF fuel
5.4.2.8	Moisture from limestone, weight fraction	0.0009	lb/lb AF fuel
5.4.2.9	Moisture from combustion air, weight fraction	0.2240	lb/lb AF fuel
5.4.3	Weight of DRY Products of Combustion - CEM Sampling Location	13.9011	lb/lb AF fuel
5.4.4	Molecular Weight, lb/lb mole DRY FG - CEM Sampling Location	30.7973	lb/lb mole
5.4.5	Weight of WET Products of Combustion - CEM Sampling Location	14.5049	lb/lb AF fuel
5.4.6	Molecular Weight, lb/lb mole WET FG - CEM Sampling Location	29.9139	lb/lb mole
		Volume Basis	
5.4.7	Flue Gas Composition, Volume Basis, % WET or DRY Flue Gas	% Wet Flue Gas	
5.4.7.1 a	Carbon Dioxide, volume percent	14.5899	percent volume
5.4.7.2 a	Sulfur Dioxide, volume percent	0.0107	percent volume
5.4.7.3 a	Oxygen from air, volume percent	3.6000	percent volume
5.4.7.4 a	Nitrogen from air, volume percent	74.7454	percent volume
5.4.7.5 a	Nitrogen from fuel, volume percent	0.1425	percent volume
5.4.7.6 a	Moisture in flue gas, volume percent	6.9115	percent volume
		100.0000	percent volume

Jacksonville Electric Authority

Unit Tested:	**Northside Unit 2**	**Boiler Efficiency:**	**92.00**
Test Date:	**August 11, 2004**		
Test Start Time:	**8:00 AM**		
Test End Time:	**12:00 PM**		
Test Duration, hours:	**4**		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

		Volume Basis % Dry Flue Gas	
5.4.7.1 b	Carbon Dioxide, volume percent	15.6732	percent volume
5.4.7.2 b	Sulfur Dioxide, volume percent	0.0115	percent volume
5.4.7.3 b	Oxygen from air, volume percent	3.8673	percent volume
5.4.7.4 b	Nitrogen from air, volume percent	80.2950	percent volume
5.4.7.5 b	Nitrogen from fuel, volume percent	0.1531	percent volume
5.4.7.6 b	Moisture in flue gas, volume percent	0.0000	percent volume
		100.0000	percent volume
5.4.8	Oxygen - MEASURED AT CEM SAMPLING LOCATION, % vol - wet l	3.6	percent volume
5.4.9	Difference Calculated versus Measured Oxygen At CEM Sample Port	0.000271249	percent
5.4.10	Sulfur Dioxide - MEASURE AT CEM SAMPLING LOCATION, ppm - c	114.9	ppm
5.4.11	Difference Calculated versus Measure Sulfur Dioxide At CEM	-5.90582E-05	percent

5.5 Determine Loss Due To Dry Gas

5.5.1 Enthalpy Coefficients For Gaseous Mixtures - From PTC 4 Sub-Section 5.19.11

	Oxygen
C0	-1.1891960E+02
C1	4.2295190E-01
C2	-1.6897910E-04
C3	3.7071740E-07
C4	-2.7439490E-10
C5	7.384742E-14

5.5.2 a	Flue Gas Constituent Enthalpy At tG15	4.613996E+01
5.5.3 a	Flue Gas Constituent Enthalpy At tA8	5.409689E+00

	Nitrogen
C0	-1.3472300E+02
C1	4.6872240E-01
C2	-8.8993190E-05
C3	1.1982390E-07
C4	-3.7714980E-11
C5	-3.5026400E-16

5.5.2 b	Flue Gas Constituent Enthalpy At tG15	5.1220847E+01
5.5.3 b	Flue Gas Constituent Enthalpy At tA8	6.0690264E+00

	Carbon Dioxide
C0	-8.5316190E+01
C1	1.9512780E-01
C2	3.5498060E-04
C3	-1.7900110E-07
C4	4.0682850E-11
C5	1.0285430E-17

5.5.2 c	Flue Gas Constituent Enthalpy At tG15	4.4578772E+01
5.5.3 c	Flue Gas Constituent Enthalpy At tA8	5.0120044E+00

	Carbon Monoxide
C0	-1.3574040E+02
C1	4.7377220E-01
C2	-1.0337790E-04
C3	1.5716920E-07
C4	-6.4869650E-11
C5	6.1175980E-15

5.5.2 d	Flue Gas Constituent Enthalpy At tG15	5.1756420E+01
5.5.3 d	Flue Gas Constituent Enthalpy At tA8	6.1223296E+00

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	Boiler Efficiency:	92.00
Test Date:	August 11, 2004		
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Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

	Sulfur Dioxide
C0	-6.7416550E+01
C1	1.8238440E-01
C2	1.4862490E-04
C3	1.2737190E-08
C4	-7.3715210E-11
C5	2.8576470E-14

5.5.2 e	Flue Gas Constituent Enthalpy At tG15	3.2488333E+01		
5.5.3 e	Flue Gas Constituent Enthalpy At tA8	3.6868506E+00		

General equation for constituent enthalpy:
h = C0 + C1 * T + C2 * T² + C3 * T³ + C4 * T * T³ + C5 * T² * T³
T = degrees Kelvin = (°F + 459.7)/1.8

5.5.4	Flue Gas Enthalpy			
5.5.5	At Measured AH Outlet Temp - tG15	49.55	Btu/lb	hFGtG15 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt *
5.5.6	At Measured AH Air Inlet Temp - tA8	5.81	Btu/lb	hFGtA8 = O2wt * hO2 + N2wt * hN2 + CO2wt * hCO2 + COwt * h
5.5.7	Dry Flue Gas Loss, as tested	633.35	Btu/lb AF fuel	
5.6	***HHV Percent Loss, as tested***	4.50	percent	

6. HEAT LOSS DUE TO MOISTURE CONTENT IN FUEL

6.1	Water Vapor Enthalpy at tG15 & 1 psia	1188.57	Btu/lb	hwvtG15 = 0.4329 * tG15 + 3.958E-05 * (tG15)² + 1062.2 - PTC
6.2	Saturated Water Enthalpy at tA8	69.63	Btu/lb	
6.3	Fuel Moisture Heat Loss, as tested	58.92	Btu/lb AF fuel	
6.4	***HHV Percent Loss, as tested***	0.42	percent	

7. HEAT LOSS DUE TO H2O FROM COMBUSTION OF H2 IN FUEL

7.1	H2O From H2 Heat Loss, as tested	365.08	Btu/lb AF fuel
7.2	***HHV Percent Loss, as tested***	2.59	percent

8. HEAT LOSS DUE TO COMBUSTIBLES (UNBURNED CARBON) IN ASH

8.1	Unburned Carbon In Ash Heat Loss	22.53	Btu/lb AF fuel
8.2	***HHV Percent Loss, as tested***	0.16	percent

9. HEAT LOSS DUE TO SENSIBLE HEAT IN TOTAL DRY REFUSE

9.1 Determine Dry Refuse Heat Loss Per Pound Of AF Fuel

9.1.1	Bottom Ash Heat Loss, as tested	3.97	Btu/lb AF fuel
9.1.2	Fly Ash Heat Loss, as tested	5.78	Btu/lb AF fuel
9.2	**Total Dry Refuse Heat Loss, as tested**	9.76	Btu/lb AF fuel
9.3	***HHV Percent Loss, as tested***	0.07	percent

Jacksonville Electric Authority

Unit Tested:	Northside Unit 2	Boiler Efficiency:	92.00
Test Date:	August 11, 2004		
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Test Duration, hours:	4		

Enter all data required in Section 1 - Note: Some cells are identified as calculated values - DO NOT enter values in these cells, imbedded formulas calculate values.

10. HEAT LOSS DUE TO MOISTURE IN ENTERING AIR

10.1 Determine Air Flow

10.1.1	Dry Air Per Pound Of AF Fuel	14.25	lb/lb AF fuel

10.2 Heat Loss Due To Moisture In Entering Air

10.2.1	Enthalpy Of Leaving Water Vapor	140.91	Btu/lb AF fuel
10.2.2	Enthalpy Of Entering Water Vapor	49.84	Btu/lb AF fuel
10.2.3	Air Moisture Heat Loss, as tested	21.88	Btu/lb

10.3 HHV Percent Loss, as tested 0.16 percent

11. HEAT LOSS DUE TO LIMESTONE CALCINATION/SULFATION REACTIONS

11.1 Loss To Calcination

11.1.1	Limestone Calcination Heat Loss	214.83	Btu/lb AF Fuel

11.2 Loss To Moisture In Limestone

11.2.1	Limestone Moisture Heat Loss	0.95	Btu/lb AF Fuel

11.3 Loss From Sulfation

11.3.1	Sulfation Heat Loss	-239.47	Btu/lb AF Fuel

11.4 Net Loss To Calcination/Sulfation

11.4.1	Net Limestone Reaction Heat Loss	-23.69	Btu/lb AF Fuel

11.5 HHV Percent Loss -0.17 percent

12. HEAT LOSS DUE TO SURFACE RADIATION & CONVECTION

12.1 HHV Percent Loss 0.27 percent

12.1.1	Radiation & Convection Heat Loss	38.37	Btu/lb AF fuel

13. SUMMARY OF LOSSES - AS TESTED/GUARANTEE BASIS

	As Tested Btu/lb AF Fuel
13.1.1	633.35
13.1.2	58.92
13.1.3	365.08
13.1.4	22.53
13.1.5	9.76
13.1.6	21.88
13.1.7	-23.69
13.1.8	38.37
	1,126.19

		As Tested Percent Loss
13.1.9	Dry Flue Gas	4.50
13.1.10	Moisture In Fuel	0.42
13.1.11	H2O From H2 In Fuel	2.59
13.1.12	Unburned Combustibles In Refuse	0.16
13.1.13	Dry Refuse	0.07
13.1.14	Moisture In Combustion Air	0.16
13.1.15	Calcination/Sulfation	-0.17
13.1.16	Radiation & Convection	0.27
		8.00
13.2	***Boiler Efficiency (100 - Total Losses), percent***	***92.00***

14. HEAT INPUT TO WATER & STEAM

14.1 Enthalpies

14.1.1	Feedwater, Btu/lb	398.84	Btu/lb
14.1.2	Blow Down, Btu/lb	579.65	Btu/lb
14.1.3	Sootblowing, Btu/lb	0.00	Btu/lb
14.1.4	Desuperheating Spray Water - Main Steam, Btu/lb	252.57	Btu/lb
14.1.5	Main Steam, Btu/lb	1448.11	Btu/lb
14.1.6	Desuperheating Spray Water - Reheat Steam, Btu/lb	284.40	Btu/lb
14.1.7	Reheat Steam - Reheater Inlet, Btu/lb	1288.59	Btu/lb
14.1.8	Reheat Steam - Reheater Outlet, Btu/lb	1510.25	Btu/lb

14.2 Heat Output 2,262,454,434 Btu/h
2,263,192,023

15. HIGHER HEATING VALUE FUEL HEAT INPUT

15.1 Determine Fuel Heat Input Based on Calculated Efficiency

15.1.1	Fuel Heat Input	2,459,103,274	Btu/h
15.1.2	Fuel Burned - CALCULATED	174,614	lb/h
15.1.3	Difference Assumed versus Calculated Fuel Burned	2.08713E-05	percent

ATTACHMENT C

CAE Test Report

Black & Veatch Corporation
10751 Deerwood Park Boulevard, Suite 130
Jacksonville, FL 32256

REPORT ON
LARGE SCALE CFB COMBUSTION DEMONSTRATION PROJECT
80% PETROLEUM COKE / 20% PITTSBURGH NO. 8 COAL

Performed for:
BLACK & VEATCH CORPORATION
UNIT 2, SDA INLET AND STACK
JEA - NORTHSIDE GENERATING STATION

Client Reference No: 137064.96.1400
CleanAir Project No: 9475-4
Revision 0: September 16, 2004

To the best of our knowledge, the data presented in this report are accurate and complete and error free, legible and representative of the actual emissions during the test program.

Submitted by,

Reviewed by,

Robert A. Preksta
Project Manager
(412) 787-9130
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Timothy D. Rodak
Manager, Pittsburgh Regional Office

CONTENTS

PROJECT OVERVIEW

The Northside Generating Station Repowering project provided JEA (formerly the Jacksonville Electric Authority) with the two largest circulating fluidized bed (CFB) boilers in the world. The agreement between the US Department of Energy (DOE) and JEA covering DOE participation in the Northside Unit 2 project required JEA to demonstrate the ability of the unit to utilize a variety of different fuels. Black and Veatch Corporation (B&V) contracted Clean Air Engineering, Inc. (CleanAir) to perform the air emission measurements required as part of the demonstration test program. This report covers air emission measurements obtained during the firing of 80% Petroleum Coke / 20% Pittsburgh No. 8 coal to the unit.

The test program included the measurement of the following parameters:

- particulate matter (PM), [SDA Inlet and Stack];
- sulfur dioxide (SO_2), [SDA Inlet];
- fluoride (F), [Stack];
- lead (Pb), [Stack];
- speciation of mercury (Hg^0, Hg^{2+}, Hg^{tp}), [SDA Inlet and Stack];
- ammonia (NH_3), {Stack].

The field portion of the test program took place at the Unit 2 SDA Inlet and Stack locations on August 10 and 11, 2004. Coordinating the field portion of the testing were:

T. Compaan – Black and Veatch
R. Huggins – Black and Veatch
W. Goodrich - JEA
K. Davis - JEA
J. Stroud - Clean Air Engineering

Table 1-1 contains a summary of the specific test locations, various reference methods and sampling periods for each of the sources sampled during the program.

The results of the test program are summarized in Table 1-2. A more detailed presentation of the test data is contained in Tables 2-1 through 2-10. Process data collected during the test program is contained in Appendix H.

PROJECT OVERVIEW

Table 1-1: Summary of Air Emission Field Test Program

Run Number	Location	Method	Analyte	Date	Start Time	End Time	Notes
1	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/10/04	09:32	10:32	(1)
2	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/10/04	12:49	13:49	
3	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/10/04	15:40	16:40	
4	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/10/04	16:55	17:55	
1	Unit 2 SDA Inlet	USEPA Method 17	Particulate	8/10/04	09:32	11:16	
2	Unit 2 SDA Inlet	USEPA Method 17	Particulate	8/10/04	12:58	14:23	
3	Unit 2 SDA Inlet	USEPA Method 17	Particulate	8/10/04	15:43	16:59	
2	Unit 2 SDA Inlet	Ontario-Hydro	Mercury	8/10/04	11:40	14:13	(2)
3	Unit 2 SDA Inlet	Ontario-Hydro	Mercury	8/10/04	14:42	17:04	
4	Unit 2 SDA Inlet	Ontario-Hydro	Mercury	8/10/04	17:34	20:06	(3)
1	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	8/10/04	09:32	12:04	
2	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	8/10/04	12:50	15:00	
3	Unit 2 Stack	USEPA Method 5/29	Particulate/Metals	8/10/04	15:40	17:49	
2	Unit 2 Stack	Ontario-Hydro	Mercury	8/10/04	11:40	14:10	(1)
3	Unit 2 Stack	Ontario-Hydro	Mercury	8/10/04	14:42	16:53	
4	Unit 2 Stack	Ontario-Hydro	Mercury	8/10/04	17:34	20:05	(3)
5	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/11/04	08:00	09:00	
6	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/11/04	09:41	10:41	
7	Unit 2 SDA Inlet	USEPA Method 6C	SO2	8/11/04	11:09	12:09	
4	Unit 2 SDA Inlet	USEPA Method 17	Particulate	8/11/04	08:00	09:14	
5	Unit 2 SDA Inlet	USEPA Method 17	Particulate	8/11/04	09:39	10:52	
6	Unit 2 SDA Inlet	USEPA Method 17	Particulate	8/11/04	11:09	12:36	
6	Unit 2 SDA Inlet	Ontario-Hydro	Mercury	8/11/04	14:46	17:03	(4)
1	Unit 2 Stack	USEPA Method 13B	Total Fluorides	8/11/04	08:00	09:09	
2	Unit 2 Stack	USEPA Method 13B	Total Fluorides	8/11/04	09:40	10:51	
3	Unit 2 Stack	USEPA Method 13B	Total Fluorides	8/11/04	11:12	12:19	
1	Unit 2 Stack	CTM-027	Ammonia	8/11/04	08:00	09:10	
2	Unit 2 Stack	CTM-027	Ammonia	8/11/04	09:40	10:48	
3	Unit 2 Stack	CTM-027	Ammonia	8/11/04	11:12	12:20	
6	Unit 2 Stack	Ontario-Hydro	Mercury	8/11/04	14:46	16:56	(4)

Notes:
(1) Run voided due to unstable SDA operation.
(2) Run 1 voided due to SDA Inlet sampling train operational problem.
(3) Problem with stack sample train dry gas meter index. Additional run was conducted as precaution. Samples were recovered and analyzed.
(4) Run 5 voided due to SDA Inlet sampling train operational problem.

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PROJECT OVERVIEW

Table 1-2:
Summary of Test Results

Source / Constituent	Sampling Method	Average Emission
Unit 2 SDA Inlet		
Sulfur Dioxide (ppmdv), Runs 2-4	EPA M6C	57
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 2-4	EPA M6C/19	0.1150
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 2-4	EPA M6C/19	0.1103
Sulfur Dioxide (ppmdv), Runs 5-7	EPA M6C	81
Sulfur Dioxide F_d-based, (lb/MMBtu), Runs 5-7	EPA M6C/19	0.1636
Sulfur Dioxide F_c-based, (lb/MMBtu), Runs 5-7	EPA M6C/19	0.1570
Particulate (gr/dscf), Runs 1-3	EPA M17	4.74
Particulate F_d-based, (lb/MMBtu), Runs 1-3	EPA M17/19	8.35
Particulate F_c-based, (lb/MMBtu), Runs 1-3	EPA M17/19	8.19
Particulate (gr/dscf), Runs 4-6	EPA M17	5.48
Particulate F_d-based, (lb/MMBtu), Runs 4-6	EPA M17/19	9.77
Particulate F_c-based, (lb/MMBtu), Runs 4-6	EPA M17/19	9.67
Mercury (lb/hr)	Ontario Hydro	9.596E-03
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	3.373E-06
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	3.331E-06
Unit 2 Stack		
Particulate (gr/dscf)	EPA M5	0.0013
Particulate (lb/hr)	EPA M5	7.04
Particulate F_d-based, (lb/MMBtu)	EPA M5/19	0.0024
Particulate F_c-based, (lb/MMBtu)	EPA M5/19	0.0024
Fluoride (lb/hr)	EPA M13B/19	<0.0149
Fluoride F_d-based, (lb/MMBtu)	EPA M13B/19	<5.3E-06
Fluoride F_c-based, (lb/MMBtu)	EPA M13B/19	<5.2E-06
Lead (lb/hr)	EPA M29	<1.283E-03
Lead F_d-based, (lb/MMBtu)	EPA M29/19	<4.424E-07
Lead F_c-based, (lb/MMBtu)	EPA M29/19	<4.382E-07
Mercury (lb/hr)	Ontario Hydro	<2.179E-04
Mercury F_d-based, (lb/MMBtu)	Ontario Hydro/19	<7.385E-08
Mercury F_c-based, (lb/MMBtu)	Ontario Hydro/19	<7.304E-08
Mercury (% Removal)	Ontario Hydro/19	98%
Ammonia (ppmdv)	CTM-027	0.27
Ammonia (lb/hr)	CTM-027	0.46
Ammonia F_d-based, (lb/MMBtu)	CTM-027/19	1.52E-04
Ammonia F_c-based, (lb/MMBtu)	CTM-027/19	1.50E-04

Notes:
1. The mass emission rate (lb/MMBtu) presented in the above table for all test parameters was calculated using a dry fuel factor (F_d) of 9,780 dscf/MMBtu and a carbon-based fuel factor (F_c) of 1,800 scf/MMBtu.
2. Total mercury emission results are shown in Table 1-2. A speciated breakdown of the mercury emissions is contained in Section 2 of the report.
3. Percent removal efficiency was calculated based on the units of F_d-based lb/MMBtu.
4. A less than symbol (<) indicates that one or more fractions were below the laboratory minimum detection limit

PROJECT MANAGER'S COMMENTS

Ontario Hydro Test Results

Each Ontario Hydro sampling train consists of five (5) sample fractions. These fractions, starting from the sampling nozzle, consist of:

1. 0.1N HNO_3 (Front-half Rinse)
2. Filter
3. KCl (Impingers 1 through 3)
4. HNO_3-H_2O_2 (Impinger 4)
5. KMnO4 (Impingers 5 through 7)

An aliquot of each reagent and an unused filter where analyzed for mercury prior to use in the field as an added quality assurance program. All reagents and the filter blank were below the minimum detection limit for mercury. Results of the pre-blank analysis are contained in Appendix D.

A total of six Ontario Hydro test runs were conducted. SDA Inlet Run 1 (sampling train impinger contents back-flushed) and SDA Inlet Run 5 (mid-test leak-check above limit) were voided prior to completion of the sampling runs.

During Run 4 at the Stack location it was noticed that the dry gas meter index units digit had stopped advancing. The location technician manually kept track of the sampled volume for the remainder of the test run. The equipment was replaced prior to the beginning of Run 5. During the recovery of the Stack Run 4, the laboratory technician noted that the KCL sample (Impingers 1 through 3) required an amount of potassium permanganate (KMNO4) solution in a greater volume than previous samples be added during the normal recovery to maintain the solutions purple color. Based on this observation, an addition test (Run 6) was conducted at the SDA Inlet and Stack locations as a contingency. The samples from Runs 2, 3, 4 and 6 were all analyzed and are presented in the report.

The additional KMNO4 solution required in the KCL (impingers 1 through 3) sample of Run 4 did not present any bias in the analysis and was therefore included in the overall test averages presented.

RESULTS

Table 2-1:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 1 through 4

Run No. [1]	1	2	3	4	Average [2]
Date (2004)	August 10	August 10	August 10	August 10	
Start Time	9:32	12:49	15:40	16:55	
End Time	10:32	13:49	16:40	17:55	
Operating Conditions					
Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	9,780	**9,780**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	1,800	**1,800**
Capacity factor (hours/year)	8,760	8,760	8,760	8,760	**8,760**
Gas Parameters [3]					
Oxygen (dry volume %)	4.1	4.1	4.1	4.0	**4.1**
Carbon dioxide (dry volume %)	15.6	15.4	15.4	15.5	**15.5**
Actual water vapor in gas (% by volume)	6.58	6.67	5.58	6.97	**6.41**
Volumetric flow rate, actual (acfm)	930,136	987,748	973,352	950,526	**970,542**
Volumetric flow rate, standard (scfm)	618,157	651,817	646,417	629,017	**642,417**
Volumetric flow rate, dry standard (dscfm)	577,474	608,313	610,348	585,144	**601,268**
Sulfur Dioxide (SO_2) - SDA Inlet					
Concentration (ppmdv)	99	44	73	54	**57**
Mass Emission Rate (lb/hr)	571	264	447	315	**342**
Mass Emission Rate (ton/year)	2,503	1,158	1,958	1,378	**1,498**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2005	0.0883	0.1482	0.1086	**0.1150**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.1902	0.0846	0.1422	0.1040	**0.1103**

[1] Run 1 voided due to ustable SDA operation.
[2] Average includes runs 2 through 4.
[3] Volumetric flows obtained from reference test methods (EPA Method 17 Runs 1 through 3 and Ontario Hydro Run 4, respectively).

RESULTS

Table 2-2:
Unit 2 – SDA Inlet – Sulfur Dioxide, Run 5 through 7

Run No.	**5**	**6**	**7**	**Average**
Date (2004)	August 11	August 11	August 11	
Start Time	8:00	9:41	11:09	
End Time	9:00	10:41	12:09	
Operating Conditions				
Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	**9,780**
Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	**1,800**
Capacity factor (hours/year)	8,760	8,760	8,760	**8,760**
Gas Parameters [1]				
Oxygen (dry volume %)	4.2	4.1	4.1	**4.1**
Carbon dioxide (dry volume %)	15.3	15.5	15.4	**15.4**
Actual water vapor in gas (% by volume)	7.07	7.19	6.68	**6.98**
Volumetric flow rate, actual (acfm)	950,127	966,369	963,274	**959,924**
Volumetric flow rate, standard (scfm)	627,598	633,299	633,037	**631,311**
Volumetric flow rate, dry standard (dscfm)	583,216	587,776	590,745	**587,245**
Sulfur Dioxide (SO_2) - SDA Inlet				
Concentration (ppmdv)	122	42	77	**81**
Mass Emission Rate (lb/hr)	712	246	456	**471**
Mass Emission Rate (ton/year)	3,118	1,076	1,999	**2,064**
Mass Emission Rate - F_d-based (lb/MMBtu)	0.2496	0.0850	0.1563	**0.1636**
Mass Emission Rate - F_c-based (lb/MMBtu)	0.2396	0.0812	0.1501	**0.1570**

[1] Volumetric flows obtained from reference test methods (EPA Method 17 Runs 4 through 6, respectively).

RESULTS

Table 2-3:
Unit 2 – SDA Inlet – Particulate Matter, Runs 1 through 3

Run No.		1	2	3	Average
Date (2004)		Aug 10	Aug 10	Aug 10	
Start Time (approx.)		09:32	12:58	15:43	
Stop Time (approx.)		11:16	14:23	16:59	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.3	4.4	4.2	**4.3**
CO_2	Carbon dioxide (dry volume %)	14.9	14.8	15.0	**14.9**
T_s	Sample temperature (°F)	300	305	300	**301**
B_w	Actual water vapor in gas (% by volume)	6.58	6.67	5.58	**6.28**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	930,136	987,748	973,352	**963,745**
Q_s	Volumetric flow rate, standard (scfm)	618,157	651,817	646,417	**638,797**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	577,474	608,313	610,348	**598,712**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	3.76	6.22	4.24	**4.74**
$E_{lb/hr}$	Particulate Rate (lb/hr)	18,601	32,450	22,197	**24,416**
$E_{T/yr}$	Particulate Rate (Ton/yr)	81,474	142,133	97,225	**106,944**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	6.61	11.01	7.42	**8.35**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	6.49	10.81	7.27	**8.19**

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RESULTS

Table 2-4:
Unit 2 – SDA Inlet – Particulate Matter, Runs 4 through 6

Run No.		**4**	**5**	**6**	**Average**
Date (2004)		Aug 11	Aug 11	Aug 11	
Start Time (approx.)		08:00	09:39	11:09	
Stop Time (approx.)		09:14	10:52	12:36	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	4.6	4.5	4.5	**4.5**
CO_2	Carbon dioxide (dry volume %)	14.6	14.6	14.5	**14.6**
T_s	Sample temperature (°F)	296	302	300	**299**
B_w	Actual water vapor in gas (% by volume)	7.07	7.19	6.68	**6.98**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	950,127	966,369	963,274	**959,924**
Q_s	Volumetric flow rate, standard (scfm)	627,598	633,299	633,037	**631,311**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	583,216	587,776	590,745	**587,245**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	4.02	7.55	4.87	**5.48**
$E_{lb/hr}$	Particulate Rate (lb/hr)	20,110	38,025	24,675	**27,603**
$E_{T/yr}$	Particulate Rate (Ton/yr)	88,084	166,548	108,075	**120,902**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	7.21	13.44	8.68	**9.77**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	7.09	13.29	8.64	**9.67**

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Table 2-5:
Unit 2 – SDA Inlet – Mercury (Ontario Hydro)

Run No.		2	3	4	6	Average
Date (2004)		Aug 10	Aug 10	Aug 10	Aug 11	
Start Time (approx.)		11:40	14:42	17:34	14:46	
Stop Time (approx.)		14:13	17:04	20:06	17:03	
Process Conditions						
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	8,760	
Gas Conditions						
O_2	Oxygen (dry volume %)	4.3000	4.3000	4.4000	4.0000	**4.2500**
CO_2	Carbon dioxide (dry volume %)	15.0000	14.8000	14.6000	15.0000	**14.8500**
T_s	Sample temperature (°F)	304.1250	303.5417	302.8333	306.7500	**304.3125**
B_w	Actual water vapor in gas (% by volume)	7.1902	6.7889	6.9748	7.3028	**7.0642**
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	940,141	945,279	950,526	962,174	**949,530**
Q_s	Volumetric flow rate, standard (scfm)	621,092	624,964	629,017	626,438	**625,378**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	576,435	582,535	585,144	580,690	**581,201**
Total Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	8.419E-03	1.000E-02	7.177E-03	1.279E-02	**9.596E-03**
$E_{T/yr}$	Rate (Ton/yr)	3.687E-02	4.380E-02	3.144E-02	5.601E-02	**4.203E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	2.997E-06	3.523E-06	2.532E-06	4.439E-06	**3.373E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.921E-06	3.480E-06	2.520E-06	4.404E-06	**3.331E-06**
Particulate Bound Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	8.044E-03	9.675E-03	7.076E-03	1.251E-02	**9.326E-03**
$E_{T/yr}$	Rate (Ton/yr)	3.523E-02	4.238E-02	3.099E-02	5.480E-02	**4.085E-02**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	2.864E-06	3.408E-06	2.497E-06	4.343E-06	**3.278E-06**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	2.791E-06	3.366E-06	2.485E-06	4.309E-06	**3.238E-06**
Oxidized Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	2.330E-04	2.139E-04	5.083E-05	2.249E-04	**1.806E-04**
$E_{T/yr}$	Rate (Ton/yr)	1.021E-03	9.367E-04	2.226E-04	9.849E-04	**7.912E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	8.295E-08	7.534E-08	1.794E-08	7.806E-08	**6.357E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	8.084E-08	7.442E-08	1.785E-08	7.745E-08	**6.264E-08**
Elemental Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	1.418E-04	1.120E-04	5.083E-05	5.111E-05	**8.895E-05**
$E_{T/yr}$	Rate (Ton/yr)	6.212E-04	4.907E-04	2.226E-04	2.238E-04	**3.896E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	5.049E-08	3.946E-08	1.794E-08	1.774E-08	**3.141E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	4.921E-08	3.898E-08	1.785E-08	1.760E-08	**3.091E-08**

Runs 1 and 5 were voided due to SDA Inlet reference method sampling train problem.

RESULTS

Table 2-6:
Unit 2 – Stack – Particulate Matter

Run No.		1	2	3	Average
Date (2004)		Aug 10	Aug 10	Aug 10	
Start Time (approx.)		09:32	12:50	15:40	
Stop Time (approx.)		12:04	15:00	17:49	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.1	4.6	4.5	**4.7**
CO_2	Carbon dioxide (dry volume %)	14.0	14.6	14.5	**14.4**
T_s	Sample temperature (°F)	222	222	223	**222**
B_w	Actual water vapor in gas (% by volume)	10.84	10.99	10.29	**10.70**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	887,455	884,598	909,668	**893,907**
Q_s	Volumetric flow rate, standard (scfm)	690,613	688,684	706,733	**695,344**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	615,780	613,032	634,025	**620,945**
Particulate Results					
C_{sd}	Particulate Concentration (gr/dscf)	0.0015	0.0014	0.0011	**0.0013**
$E_{lb/hr}$	Particulate Rate (lb/hr)	7.76	7.52	5.83	**7.04**
$E_{T/yr}$	Particulate Rate (Ton/yr)	34.0	32.9	25.5	**30.8**
E_{Fd}	Particulate Rate - F_d-based (lb/MMBtu)	0.0027	0.0026	0.0019	**0.0024**
E_{Fc}	Particulate Rate - F_c-based (lb/MMBtu)	0.0027	0.0025	0.0019	**0.0024**

RESULTS

Table 2-7:
Unit 2 – Stack - Fluoride

Run No.		1	2	3	Average
Date (2004)		Aug 11	Aug 11	Aug 11	
Start Time (approx.)		08:00	09:40	11:12	
Stop Time (approx.)		09:09	10:51	12:19	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	5.3	5.2	**5.2**
CO_2	Carbon dioxide (dry volume %)	14.0	13.9	14.0	**14.0**
T_s	Sample temperature (°F)	217	225	221	**221**
B_w	Actual water vapor in gas (% by volume)	10.07	10.58	10.14	**10.26**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	893,168	887,307	857,987	**879,487**
Q_s	Volumetric flow rate, standard (scfm)	695,578	683,276	664,907	**681,254**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	625,531	610,997	597,495	**611,341**
Hydrogen Fluoride (HF) Results [1]					
C_{sd}	HF Concentration (ppmdv)	<0.0074	<0.0079	<0.0082	**<0.0078**
$E_{lb/hr}$	HF Rate (lb/hr)	<0.0145	<0.0150	<0.0152	**<0.0149**
$E_{kg/hr}$	HF Rate (kg/hr)	<0.0066	<0.0068	<0.0069	**<0.0068**
$E_{T/yr}$	HF Rate (Ton/yr)	<0.0635	<0.0659	<0.0665	**<0.0653**
E_{Fd}	HF Rate - Fd-based (lb/MMBtu)	<5.0E-06	<5.4E-06	<5.5E-06	**<5.3E-06**
E_{Fc}	HF Rate - Fc-based (lb/MMBtu)	<5.0E-06	<5.3E-06	<5.4E-06	**<5.2E-06**

[1] A less than symbol (<) indicates that one or more fractions were below the laboratory minimum detection limit.

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RESULTS

Table 2-8:
Unit 2 – Stack – Lead

Run No.		1	2	3	Average
Date (2004)		Aug 10	Aug 10	Aug 10	
Start Time (approx.)		09:32	12:50	15:40	
Stop Time (approx.)		12:04	15:00	17:49	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.1	4.6	4.5	**4.7**
CO_2	Carbon dioxide (dry volume %)	14.0	14.6	14.5	**14.4**
T_s	Sample temperature (°F)	222	222	223	**222**
B_w	Actual water vapor in gas (% by volume)	10.84	10.99	10.29	**10.70**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	887,455	884,598	909,668	**893,907**
Q_s	Volumetric flow rate, standard (scfm)	690,613	688,684	706,733	**695,344**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	615,780	613,032	634,025	**620,945**
Lead Results - Total [1]					
$E_{lb/hr}$	Rate (lb/hr)	<2.225E-03	<1.235E-03	<3.874E-04	**<1.283E-03**
$E_{T/yr}$	Rate (Ton/yr)	<9.745E-03	<5.411E-03	<1.697E-03	**<5.617E-03**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.790E-07	<4.211E-07	<1.269E-07	**<4.424E-07**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.742E-07	<4.140E-07	<1.264E-07	**<4.382E-07**

[1] A less than symbol (<) indicates that one or more fractions were below the laboratory minimum detection limit.

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RESULTS

Table 2-9:
Unit 2 – Stack – Mercury (Ontario Hydro)

Run No.		2	3	4	6	Average
Date (2004)		Aug 10	Aug 10	Aug 10	Aug 11	
Start Time (approx.)		11:40	14:42	17:34	14:46	
Stop Time (approx.)		14:10	16:53	20:05	16:56	
Process Conditions						
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	8,760	
Gas Conditions						
O_2	Oxygen (dry volume %)	4.7000	4.6000	5.0000	4.6000	**4.7250**
CO_2	Carbon dioxide (dry volume %)	14.4000	14.6000	14.2000	14.4000	**14.4000**
T_s	Sample temperature (°F)	220.4583	221.7083	222.0833	220.7083	**221.2396**
B_w	Actual water vapor in gas (% by volume)	10.3893	9.9749	10.6272	10.2990	**10.3226**
Gas Flow Rate						
Q_a	Volumetric flow rate, actual (acfm)	895,569	884,328	882,007	868,644	**882,637**
Q_s	Volumetric flow rate, standard (scfm)	698,378	688,347	686,163	672,297	**686,296**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	625,821	619,685	613,243	603,058	**615,452**
Total Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	<4.628E-04	<2.168E-04	<8.703E-05	<1.050E-04	**<2.179E-04**
$E_{T/yr}$	Rate (Ton/yr)	<2.027E-03	<9.495E-04	<3.812E-04	<4.598E-04	**<9.543E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<1.555E-07	<7.311E-08	<3.041E-08	<3.638E-08	**<7.385E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<1.541E-07	<7.188E-08	<2.998E-08	<3.626E-08	**<7.304E-08**
RE	Removal Efficiency - Fd-based (lb/MMBtu)	94.8%	97.9%	98.8%	99.2%	**98%**
Particulate Bound Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	<2.152E-05	<3.172E-05	<2.176E-05	<4.199E-05	**<2.925E-05**
$E_{T/yr}$	Rate (Ton/yr)	<9.427E-05	<1.390E-04	<9.530E-05	<1.839E-04	**<1.281E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	<7.232E-09	<1.070E-08	<7.602E-09	<1.455E-08	**<1.002E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	<7.165E-09	<1.052E-08	<7.496E-09	<1.451E-08	**<9.921E-09**
Oxidized Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	1.399E-04	1.163E-04	<4.352E-05	<4.199E-05	**<8.543E-05**
$E_{T/yr}$	Rate (Ton/yr)	6.128E-04	5.095E-04	<1.906E-04	<1.839E-04	**<3.742E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	4.701E-08	3.923E-08	<1.520E-08	<1.455E-08	**<2.900E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	4.657E-08	3.857E-08	<1.499E-08	<1.451E-08	**<2.866E-08**
Elemental Mercury Results						
$E_{lb/hr}$	Rate (lb/hr)	3.121E-04	8.460E-05	5.439E-05	6.298E-05	**1.285E-04**
$E_{T/yr}$	Rate (Ton/yr)	1.367E-03	3.705E-04	2.382E-04	2.759E-04	**5.629E-04**
E_{Fd}	Rate - Fd-based (lb/MMBtu)	1.049E-07	2.853E-08	1.900E-08	2.183E-08	**4.356E-08**
E_{Fc}	Rate - Fc-based (lb/MMBtu)	1.039E-07	2.805E-08	1.874E-08	2.176E-08	**4.311E-08**

[1] A less than symbol (<) indicates that one or more fractions were below the laboratory minimum detection limit.

Runs 1 and 5 were voided due to SDA Inlet reference method sampling train problem.

RESULTS

Table 2-10:
Unit 2 – Stack - Ammonia

Run No.		1	2	3	Average
Date (2004)		Aug 11	Aug 11	Aug 11	
Start Time (approx.)		08:00	09:40	11:12	
Stop Time (approx.)		09:10	10:48	12:20	
Process Conditions					
F_d	Oxygen-based F-factor (dscf/MMBtu)	9,780	9,780	9,780	
F_c	Carbon dioxide-based F-factor (dscf/MMBtu)	1,800	1,800	1,800	
Cap	Capacity factor (hours/year)	8,760	8,760	8,760	
Gas Conditions					
O_2	Oxygen (dry volume %)	5.0	4.8	4.7	**4.8**
CO_2	Carbon dioxide (dry volume %)	14.0	14.4	14.4	**14.3**
T_s	Sample temperature (°F)	222	229	225	**225**
B_w	Actual water vapor in gas (% by volume)	10.47	11.04	11.17	**10.89**
Gas Flow Rate					
Q_a	Volumetric flow rate, actual (acfm)	929,320	940,000	917,525	**928,948**
Q_s	Volumetric flow rate, standard (scfm)	718,866	719,300	706,032	**714,733**
Q_{std}	Volumetric flow rate, dry standard (dscfm)	643,634	639,870	627,190	**636,898**
Ammonia (NH_3) Results					
C_{sd}	Ammonia Concentration (ppmdv)	0.33	0.27	0.21	**0.27**
$E_{lb/hr}$	Ammonia Rate (lb/hr)	0.56	0.45	0.36	**0.46**
$E_{kg/hr}$	Ammonia Rate (kg/hr)	0.25	0.21	0.16	**0.21**
$E_{T/yr}$	Ammonia Rate (Ton/yr)	2.45	1.98	1.56	**1.99**
E_{Fd}	Ammonia Rate - Fd-based (lb/MMBtu)	1.86E-04	1.50E-04	1.19E-04	**1.52E-04**
E_{Fc}	Ammonia Rate - Fc-based (lb/MMBtu)	1.86E-04	1.47E-04	1.18E-04	**1.50E-04**

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DESCRIPTION OF INSTALLATION

PROCESS DESCRIPTION

The Jacksonville Electric Northside Generating Station Unit 2 consists of a 300 MW circulating fluidized bed (CFB) boiler a lime-based spray dryer absorber (SDA) and a pulse jet fabric filter (PJFF).

The SDA has sixteen independent dual-fluid atomizers. The fabric filter has eight isolatable compartments. The control system also uses reagent preparation and byproduct handling subsystems. The SDA byproduct solids/fly ash collected by the PJFF is pneumatically transferred from the PJFF hoppers to either the Unit 2 fly ash silo or the Unit 2 AQCS recycle bin. Fly ash from the recycle bin is slurried and reused as the primary reagent by the SDA spray atomizers. The reagent preparation system converts quicklime (CaO), which is delivered dry to the station, into a hydrated lime [$Ca(OH)_2$] slurry, which is fed to the atomizers as a supplemental reagent.

The testing reported in this document was performed at the Unit 2 SDA Inlet and Stack locations.

A schematic of the process indicating sampling locations is shown in Figure 3-1.

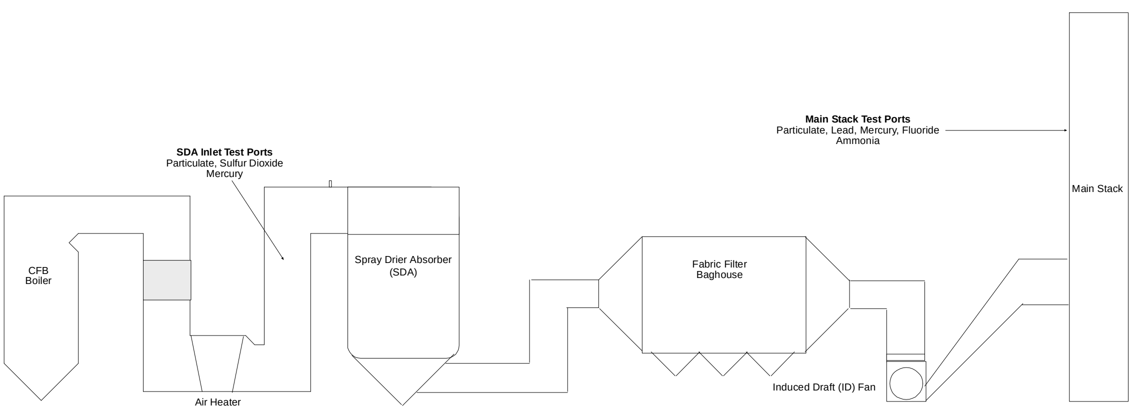


Figure 3-1: Process Schematic

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION(S)

Sampling point locations were determined according to EPA Method 1.

Table 3-1 outlines the sampling point configurations. Figure 3-3 and 3-3 illustrate the sampling points and orientation of sampling ports for each of the sources tested in the program.

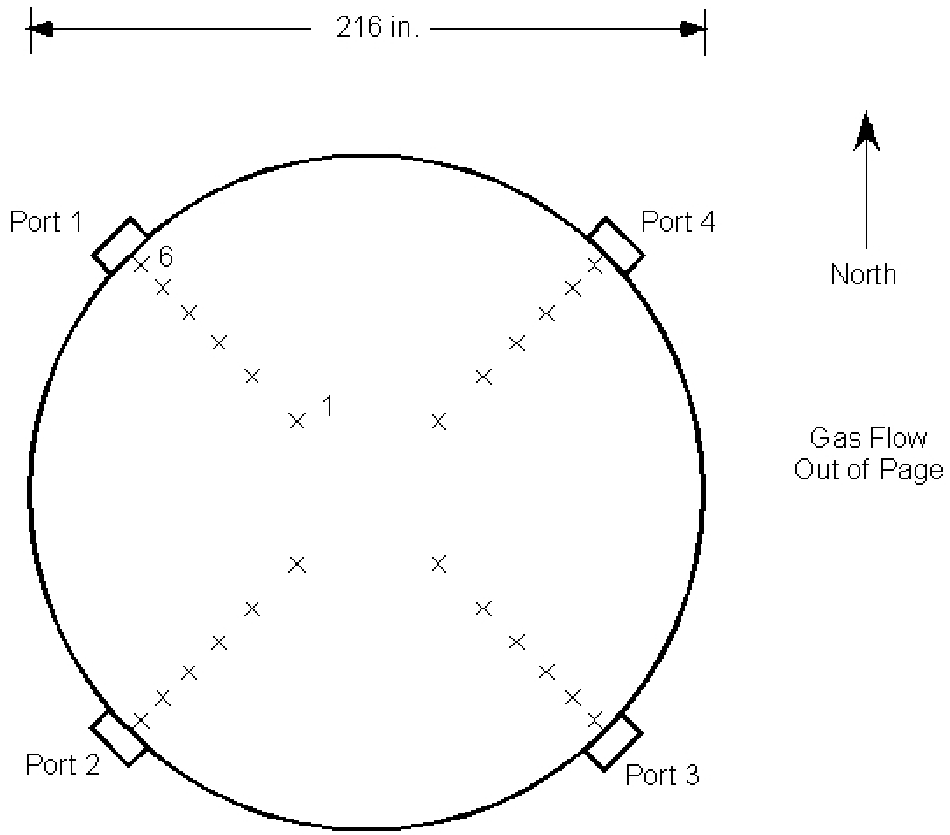
Table 3-1:
Sampling Points

Location	Constituent	Method	Run No.	Ports	Points per Port	Minutes per Point	Total Minutes	Figure
Unit 2 SDA Inlet	SO2	6C	1-7	1	1	60[1]	60	N/A
Unit 2 SDA Inlet	Particulate	17	1-6	4	6	2.5	60	3-1
Unit 2 SDA Inlet	Mercury	OH[2]	1-6	4	6	5	120	3-1
Unit 2 Stack	Particulate	5	1-3	4	3	10	120	3-2
Unit 2 Stack	Fluoride	13B	1-3	4	3	5	60	3-2
Unit 2 Stack	Lead	29	1-3	4	3	10	120	3-2
Unit 2 Stack	Mercury	OH[2]	1-6	4	3	10	120	3-2
Unit 2 Stack	Ammonia	CTM-027	1-3	4	3	5	60	3-2

[1] Sulfur Dioxide was sampled from a single point in the duct. Readings were collected at one-second intervals by the computer based data acquisition system and reported as one-minute averages.
[2] Mercury was determined using the Ontario Hydro method. Runs 1 and 5 were voided due to operational problems with the SDA Inlet reference method sampling train.

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



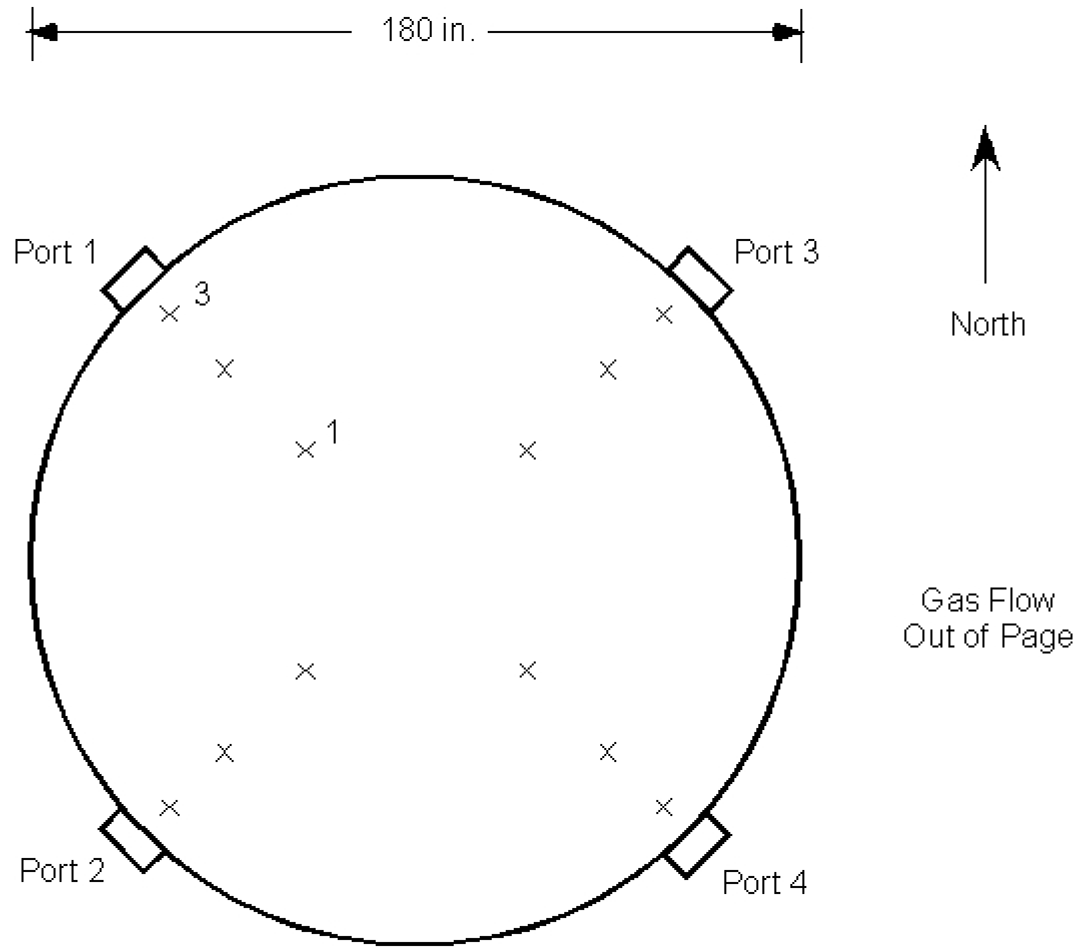
Sampling Point	Port to Point Distance (in.)
1	76.9
2	54.0
3	38.2
4	25.5
5	14.5
6	4.5

Diameters to upstream disturbance: >2.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >0.5 Limit: 0.5 (minimum)

Figure 3-2: SDA Inlet Sampling Point Determination (EPA Method 1)

DESCRIPTION OF INSTALLATION

DESCRIPTION OF SAMPLING LOCATION (CONTINUED)



Sampling Point	Port to Point Distance (in.)
1	53.3
2	26.3
3	7.9

Diameters to upstream disturbance: >8.0 Limit: 2.0 (minimum)
Diameters to downstream disturbance: >2.0 Limit: 0.5 (minimum)

Figure 3-3: Stack Sampling Point Determination (EPA Method 1)

METHODOLOGY

Clean Air Engineering followed procedures as detailed in U.S. Environmental Protection Agency (EPA) Methods 1, 2, 3A, 4, 5, 6C, 13B, 17, 29, Conditional Test Method CTM-027 and the Ontario Hydro Method. The following table summarizes the methods and their respective sources.

Table 4-1:
Summary of Sampling Procedures

<u>Title 40 CFR Part 60 Appendix A</u>	
Method 1	"Sample and Velocity Traverses for Stationary Sources"
Method 2	"Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)"
Method 3A	"Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 4	"Determination of Moisture Content in Stack Gases"
Method 5	"Determination of Particulate Emissions from Stationary Sources"
Method 6C	"Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)"
Method 13B	"Determination of Total Fluoride Emissions from Stationary Sources (Specific Ion Electrode Method)"
Method 17	"Determination of Particulate Emissions from Stationary Sources (In-Stack Filtration Method)"
Method 29	"Determination of Metals Emissions from Stationary Sources"
<u>Conditional Test Method</u>	
CTM-027	"Procedure for the Collection and Analysis of Ammonia in Stationary Sources."
<u>Draft Methods</u>	
Ontario Hydro	"Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources."

The EPA Methods (1 through 29) appear in detail in Title 40 of the Code of Federal Regulations (CFR). The Conditional Test Method and the Ontario Hydro Method appear in detail on the US EPA Emissions Measurement Center web page. All methods may be found on the World Wide Web at http://www.cleanair.com.

Diagrams of the sampling apparatus and major specifications of the sampling, recovery and analytical procedures are summarized for each method in Appendix A.

Clean Air Engineering followed specific quality assurance and quality control (QA/QC) procedures as outlined in the individual methods and in USEPA "Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III Stationary Source-Specific Methods", EPA/600/R-94/038C. Additional QA/QC methods as prescribed in Clean Air's internal Quality Manual were also followed. Results of all QA/QC activities performed by Clean Air Engineering are summarized in Appendix D.

APPENDIX

ATTACHMENT D

PI Data Summary

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - PI DATA

	Date:	**August 10, 2004**	**August 11, 2004**
	Start:	**0930 hours**	**0800 hours**
	End:	**1330 hours**	**1200 hours**

Substance	**Characteristic Being Measured**	**Values Used in Efficiency Calculation**	
Primary Air	Avg. Out A and B, Deg F	125.76	122.69
	Average, deg F	103.30	103.13
	Count	482.00	480.00
	Standard Deviation	4.20	3.44
Secondary Air	Total SA flow, klb/hr	0.70	0.67
	Average, Total SA Flow, klb/hr	0.14	0.24
	Count	241.00	240.00
	Standard Deviation	0.08	0.07
	Avg. Out A and B, Deg F	122.50	119.31
	Average, deg F	99.31	99.13
	Count	482.00	480.00
	Standard Deviation	5.55	4.97
Fuel	Total Flow, klb/hr	189.53	186.89
	Average, deg F	186.88	186.98
	Count	241.00	240.00
	Standard Deviation	2.56	1.92
PAHTR Gas Out	Gas Out, deg F, A train	291.39	286.06
	Gas Out, deg F, B train	299.31	293.58
	Average, deg F	297.23	294.54
	Count	482.00	480.00
	Standard Deviation	4.34	4.70
SAHTR Gas Out	Gas Out, deg F, A train	276.14	270.57
	Gas Out, deg F, B train	288.39	282.00
	Average, deg F	279.60	277.17
	Count	482.00	480.00
	Standard Deviation	10.73	10.82
PAH Gas In	Gas In, deg F, A & B train	527.65	518.41
	Average, deg F	525.02	521.61
	Count	241.00	240.00
	Standard Deviation	3.04	3.81
SAH Gas In	Gas In, deg F A & B train	531.49	522.17
	Average, deg F	528.62	524.82
	Count	241.00	240.00
	Standard Deviation	3.33	3.85
PAH Air Out	Air Out, deg F A & B train	430.13	422.74
	Average, deg F	429.87	426.95
	Count	241.00	240.00
	Standard Deviation	2.14	2.77

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
	Air Out, deg F A & B train	403.63	396.31
SA Airheater Air Out	Average, deg F	402.59	400.34
	Count	241.00	240.00
	Standard Deviation	2.17	2.61
	Ash leaving temperature, deg F, A	218.39	343.74
	Ash leaving temperature, deg F, B	107.46	107.39
Stripper/ Coolers - A, B, C, D	Ash leaving temperature, deg F, C	320.62	289.34
	Ash leaving temperature, deg F, D	401.13	221.59
	Average, deg F	276.61	234.89
	Count	482.00	480.00
	Standard Deviation	130.02	82.48
	Temperature, deg F		
SDA Hopper	Average, deg F	186.13	190.72
	Count	241.00	240.00
	Standard Deviation	2.92	4.33
	Feedrate, feeders 1, 2, 3, lb/hr	50,849.82	51,530.02
Limestone Feed Rate 1	Average, lb/hr	50,892.17	50,404.87
	Count	241.00	240.00
	Standard Deviation	3.36	3.39
	AH inlet, ppm		
SO2, in flue Gas	Average, ppm mv	22.09	30.33
	Count	241.00	240.00
	Standard Deviation	29.45	17.45
	Flow to A, B, C, lb/hr	41,750.20	41,776.20
Intrex Blower Air Flow	Average, lb/hr	42,094.07	41,812.89
	Count	1,446.00	1,440.00
	Standard Deviation	142.04	187.44
	PA Flow to Intrex A, B, C, lb/hr	42,386.11	41,009.07
Intrex Seal Pot Blower	Average, lb/hr	42,116.34	41,538.12
	Count	241.00	240.00
	Standard Deviation	357.57	412.51
Intrex Blower Exit Air Temp	Average, deg F	184.97	181.93
	Count	241.00	240.00
	Standard Deviation	2.57	2.63
Seal Pot Blower Exit Air Temp	Average, deg F	205.39	200.49
	Count	241.00	240.00
	Standard Deviation	1.43	2.76
Feedwater Temperature to Econ	Average, deg F	420.15	419.93
	Count	241.00	240.00
	Standard Deviation	1.01	0.67
Feedwater Pressure to Econ	Average, psig	2,443.32	2,443.92
	Count	241.00	240.00
	Standard Deviation	6.45	5.02

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
(DSH)SH-1 Spray Flow	Average, klb/hr	27.03	19.36
	Count	241.00	240.00
	Standard Deviation	4.96	3.14
SH-1 Spray Temperature	Average, deg F	279.70	278.29
	Count	241.00	240.00
	Standard Deviation	1.89	1.88
SH-1 Spray Pressure	Average, psig	2,693.33	2,695.47
	Count	241.00	240.00
	Standard Deviation	7.27	5.80
Drum Pressure	Average of three pressure values, psig	2,565.37	2,559.84
	Average, psig	1,253.87	1,242.55
	Count	723.00	720.00
	Standard Deviation	7.07	5.88
Main Steam Temperature	Average, deg F	980.27	980.48
	Count	241.00	240.00
	Standard Deviation	1.56	1.76
Main Steam Pressure	Average of two pressure values, psig	978.79	2,397.78
	Average, psig	980.01	2,400.68
	Count	482.00	480.00
	Standard Deviation	1.76	3.15
Reheater Outlet Temperature	Average of three temp values, deg F	988.48	987.00
	Average, deg F	989.23	988.40
	Count	723.00	720.00
	Standard Deviation	1.46	2.52
Reheater Outlet Pressure	Average of two pressure values, psig	591.03	593.67
	Average, psig	592.57	590.78
	Count	482.00	480.00
	Standard Deviation	25.94	25.45
CRH Ent Attemp Temp	Average, deg F	599.45	598.95
	Count	241.00	240.00
	Standard Deviation	3.38	2.24
CRH Ent Attemp Press	Average, psig	593.52	591.57
	Count	241.00	240.00
	Standard Deviation	8.13	6.01
RH Spray Flow	Average, klb/hr	0.04	0.04
	Count	241.00	240.00
	Standard Deviation	0.02	0.01
RH Spray Temp	Average, deg F	312.94	312.85
	Count	241.00	240.00
	Standard Deviation	0.94	0.22

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
RH Spray Pressure	Average, psig	933.66	933.76
	Count	241.00	240.00
	Standard Deviation	3.13	2.33
Htr 1 FW Entering Temp	Data	418.87	419.64
	Data	419.16	420.60
	Average, deg F	419.74	419.52
	Count	482.00	480.00
	Standard Deviation	1.10	0.81
Htr 1 FW Entering Pressure	Data	2,449.47	2,443.91
	Data	2,449.47	2,443.91
	Average, psig	2,443.32	2,443.92
	Count	482.00	480.00
	Standard Deviation	6.44	5.02
Htr 1 FW Leaving Temp	Average, deg F	420.15	419.93
	Count	241.00	240.00
	Standard Deviation	1.01	0.67
Htr 1 FW Leaving Pressure	Average, psig	2,443.32	2,443.92
	Count	241.00	240.00
	Standard Deviation	6.45	5.02
Htr 1 Extraction Stm Temp	Average, deg F	410.79	411.95
	Count	241.00	240.00
	Standard Deviation	0.86	0.34
Htr 1 Extraction Stm Pressure	Average, psig	139.10	151.66
	Count	241.00	240.00
	Standard Deviation	1.14	1.18
Htr 1 Drain Temp	Average, deg F	385.08	388.90
	Count	0.00	0.00
	Standard Deviation	0.82	0.36
Htr 1 Drain Pressure	Average, psig	139.10	151.66
	Count	241.00	240.00
	Standard Deviation	1.14	1.18
Feedwater to Econ	Pressure, psig	2,464.22	2,458.59
	Temperature, deg F	419.16	420.60
	Density, lb / cu. ft.	53.59	53.53
Primary Air to SC A	Total of three flow values, lb/hr	30,873.04	31,406.32
	Average, lb/hr	31,084.80	31,197.92
	Count	241.00	240.00
	Standard Deviation	0.53	0.19
Primary Air to SC B	Total of three flow values, lb/hr	5,072.05	5,112.73
	Average, lb/hr	4,989.37	4,999.84
	Count	241.00	240.00
	Standard Deviation	0.04	0.06

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - PI DATA

Substance	Characteristic Being Measured	Values Used in Efficiency Calculation	
Primary Air to SC C	Total of three flow values, lb/hr	12,050.20	11,954.20
	Average, lb/hr	12,039.02	12,004.02
	Count	241.00	240.00
	Standard Deviation	0.12	0.06
Primary Air to SC D	Total of three flow values, lb/hr	18,662.74	30,148.09
	Average, lb/hr	18,761.27	29,990.43
	Count	241.00	240.00
	Standard Deviation	0.16	0.13
Combustion Air Flow into PAH (hot), lb/hr	Total of fourteen flow values, lb/hr	1,270,324.05	1,274,032.87
	Average, lb/hr	1,266,175.50	1,266,405.67
	Count	241.00	240.00
	Standard Deviation	49.78	55.17
Combustion Air Flow bypassing PAH (cold), lb/hr	Total of four flow values, lb/hr	20,012.66	22,989.46
	Average, lb/hr	20,126.80	23,008.37
	Count	241.00	240.00
	Standard Deviation	0.17	0.12
Total air Flow, klb/hr	Average, lb/hr	2,411,350.98	2,425,061.16
	Count	241.00	240.00
	Standard Deviation	21.34	13.67

ATTACHMENT E

Abbreviation List - Refer to Section 1.2

ATTACHMENT F

Isolation Valve List

Hole #	Description	Approximate Location	Closed (Yes / No)			
			13-Jan-04	14-Jan-04	15-Jan-04	16-Jan-04
37	RHA to CRH	Next to Heat 1	closed	closed	closed	closed
Use Digital Readout	MS Bypass to CRH (Upstream)	Next to Heater 1	closed	closed	closed	closed
38	Desup Wtr from BFP Disch to MS Bypass		closed	closed	closed	closed
Bare Pipe	Heater 1 ~~Running~~ Vent	On Side of Heater 1	closed	closed	closed	closed
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	closed	closed	closed	closed
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	closed	closed	closed	closed
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	closed	closed	closed	closed
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	closed	closed	closed	closed
33	Aux Steam Header (GRAY Valve) 337	Platform Overhead	closed	closed	closed	closed
55	CRH Line Drains - common line	Below Turbine	closed	closed	~~open~~ closed	closed
56	CRH Line Drains - common line	Below Turbine	closed	closed	closed	closed
57	CRH Line Drains - North	Below Turbine	closed	closed	closed	closed
58	CRH Line Drains - South	Below Turbine	closed	closed	closed	closed
60	MS Line Drain	Below Turbine	closed	closed	closed	closed
61	MS Line Drain	Below Turbine	closed	closed	closed	closed
#1	Extraction Drain	Below Turbine	closed	closed	closed	closed
	Heat Soak Valve 5A330	Below Turbine	closed	closed	closed	closed

#1 Heater shell drain leaking small amount

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
Mezzanine Level			
35	DA Pegging Steam (Upstream)	Next to Heater 1	
36	DA Pegging Steam (Downstream)	Next to Heater 1	
34	DA Pegging Steam Line Drain	Next to Heater 1	
37	RHA to CRH	Next to Heater 1	
39	MS Bypass to CRH (Upstream)	Over railing by Heater 1	
Use Digital Readout	MS Bypass to CRH (Downstream)	Next to Heater 1	
38	Desup Wtr from BFP Disch to MS Bypass	Near railing by Heater 1	
Bare Pipe	Heater 1 Running Vent	On Side of Heater 1	
Bare Pipe	Heater 1 Relief Vent	Top of Heater 1	
Visual	Heater 1 FW Bypass	Directly above Heater 1	
Bare Pipe	Heater 2 Running Vent	On Side of Heater 2	
Bare Pipe	Heater 2 Relief Vent	Top of Heater 2	
Visual	Heater 2 FW Bypass	Directly above Heater 2	
41	Aux Steam to Unit 3 CRH	Against wall - stairs near Htr 5	
40	Aux Steam from Unit 3 CRH	Against wall - stairs near Htr 5	
42	MS to SSH	Platform (overhead)	
43	SSR Bypass Line	Platform (overhead)	
44	Aux Steam Supply Line to SSR	Vertical Pipe near Platform	
Gauge	SSH Pressure	Board on Platform	
45	Heater 4 Running Vent	Side of Heater 4	
Bare Pipe	Heater 4 Relief Vent	Top of Heater 4	
Visual	Heater 4 FW Bypass	Directly above Heater 4	
46	Heater 5 Vent	Side of Heater 5	
47	Heater 5 Vent	Side of Heater 5	
Bare Pipe	Heater 5 Relief Vent	Top of Heater 5	
Visual	Heater 5 FW Bypass	Directly above Heater 5	
48	CBP Disch to BFP Suction	To the side of Heater 5	
Visual	Heater 6 FW Bypass	Near Condenser Wall	
19	BDV to Cond	Near Condenser Wall (right side)	
20	RFDV (Ventilator Valve) to Cond	Bare Pipe near Cond Wall (R/S)	
21	Equalizer Valve to Cond (CRV-1)	Bare Pipe near Cond Wall (R/S)	
22	Equalizer Valve to Cond (CRV-2)	Bare Pipe near Cond Wall (R/S)	
12	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
14	MS SV Below Seat Drains to Cond	Below MS Stop Valves	
52	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
53	MS SV Above Seat Drains to Cond	Below MS Stop Valves	
13	Stm Lead Drains	Near Condenser Wall (R/S)	
16	Stm Lead Drains	Near Condenser Wall (R/S)	
17	Stm Lead Drains	Near Condenser Wall (R/S)	
18	Stm Lead Drains	Near Condenser Wall (R/S)	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
15	CRV Drain Lines	Near HRH Line	
23	CRV Drain Lines	Hear HRH Line	
49	HRH Bypass to Condenser (Upstream)	Bypass line upstream of valve	
DCS	HRH Bypass to Condenser (Downstream)	Control Room	
50	Desup Wtr from BFP Disch to HRH Byp	Vertical Pipe near HRH Bypass	
Visual	SDBFP Recirc to DA	Near HRH Bypass Line	
Visual	MDBFP Recirc to DA	Near HRH Bypass Line	
	Condenser Vacuum		

Ground Floor

Hole #	Description	Approximate Location	Temp Check
24	TDV to Cond (SS Dump)	Into Condenser (use platform)	
7	CRH Drain Hdr 1	Hdr into Cond on Left Side	
8	MS Drain Hdr 2	Hdr into Cond on Left Side	
6	Extraction Drain Hdr 3	Hdr into Cond on Left Side	
10	Drain Hdr 4	Hdr into Cond on Right Side	
9	Drain Hdr 5	Hdr into Cond on Right Side	
11	Steam Lead Drains	Bare Pipe - Side of Condenser	
51	BAC Return to Condenser (CV-4)	U/S of CV-4	
Double Isolate	Hotwell Makeup		
	Polisher Drains	Near Condensate Polishing Sys	
	Bitter Water Pump Off	Near Condensate Polishing Sys	Yes / No
	Unit 2 Fill Pump Off	Near Condensate Polishing Sys	Yes / No
1 / 25	Htr 1 Dump to Cond	Up/Downstream of Valve	/
2	Htr 6 Dump to Cond	Upstream of Valve	
3 / 26	Htr 2 Dump to Cond	Up/Downstream of Valve	/
4 / 27	Htr 4 Dump to Cond	Up/Downstream of Valve	/
5 / 28	Htr 5 Dump to Cond	Up/Downstream of Valve	/
29	Aux Stm to CRH Warm. (U/S of Check Vlv)	Platform Overhead	
30	Aux Stm to CRH Warm. (D/S of Check Vlv)	Platform Overhead	
31	Aux Steam to/from Unit 3 CRH	Platform Overhead	
32	Aux Steam to SSH	Platform Overhead	
33	Aux Steam Header Gray Valve	Platform Overhead	
54	HRH Line Drains	Below Turbine	
59	HRH Line Drains	Below Turbine	
55	CRH Line Drains - common line	Below Turbine	
56	CRH Line Drains - common line	Below Turbine	
57	CRH Line Drains - North	Below Turbine	
58	CRH Line Drains - South	Below Turbine	
60	MS Line Drain	Below Turbine	
61	MS Line Drain	Below Turbine	
	#1 Extr Drain Heat Soak Valve	Below Turbine	

Cycle Isolation Checklist

Hole #	Description	Approximate Location	Temp Check
	Hotwell Make-Up Valves		
	Boiler Blow Down Valve		
	Valve SA 328 (turbine soak line)		
	Auxiliary Steam Supply to Seal Steam System		
	Valve 331 Auxiliary Steam from Cold RH		
	Reheat Attemperator		
	Heater #1 Continuous Vent		
	Heater #2 Continuous Vent		
	Heater #4 Continuous Vent		
	Heater #5 Continuous Vent		

ATTACHMENT G

Fuel Analyses - 80/20 Blend Pet Coke and Pittsburgh 8 Coal

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - FUEL ANALYSES

August 10 - 11, 2004

Fuel Coal	Pet Coke		Pittsburgh 8 (Fdrs A1, E1)		80% Pet Coke / 20 % Pittsburgh 8	
Lab Number	71-242403	71-242404	71-241475	71-241476		
Date	10-Aug-04	11-Aug-04	10-Aug-04	11-Aug-04	10-Aug-04	11-Aug-04
Time	4 hours	4 hours	4 hours	4 hours	4 hours	4 hours
Proximate Analysis						
Moisture, wt%	5.37	5.18	5.20	5.26	5.34	5.20
Ash, wt%	0.37	0.34	10.17	10.71	2.33	2.41
Volatile, wt%	8.80	8.69	34.65	33.96	13.97	13.74
Fixed Carbon, wt%	85.46	85.79	49.98	50.07	78.36	78.65
Ultimate Analysis						
Carbon, wt%	83.78	84.83	71.66	71.39	81.36	82.14
Hydrogen, wt%	3.35	3.39	4.76	4.79	3.63	3.67
Nitrogen, wt%	2.10	2.14	1.23	1.18	1.93	1.95
Sulfur, wt%	3.96	4.01	2.67	2.68	3.70	3.74
Moisture, wt%	5.37	5.18	5.20	5.26	5.34	5.20
Ash, wt%	0.37	0.34	10.17	10.71	2.33	2.41
Oxygen, wt%	1.07	0.11	4.31	3.99	1.72	0.89
Higher Heating, Btu/lb	14420	14434	12747	12668	14,085	14,081
Total Chlorine, wt%	0.02	0.01	0.09	0.09	0.03	0.03
Total Fluorine, ug/g	26.00	26.00	73.00	85.00	35.4	37.8
Total Mercury, ug/g	0.05	0.04	0.07	0.09	0.054	0.050
Total Lead, ug/g	3.00	4.00	7.00	7.00	3.800	4.600
Moisture (oven), wt%						
Mineral analysis						
SiO_2, wt%	5.03	5.16	47.22	47.12	13.47	13.55
Al_2O_3, wt%	2.45	2.36	22.58	23.08	6.48	6.50
Ti_2O, wt%	0.43	0.41	1.12	1.11	0.57	0.55
Fe_2O_3, wt%	6.76	6.58	16.24	15.04	8.66	8.27
CaO, wt%	1.64	1.68	4.42	4.51	2.20	2.25
MgO, wt%	0.25	0.22	0.90	0.90	0.38	0.36
K_2O, wt%	0.10	0.06	1.73	1.72	0.43	0.39
Na_2O, wt%	5.90	5.72	0.84	0.70	4.89	4.72
SO_3, wt%	6.03	7.63	3.97	3.69	5.62	6.84
P_2O_5, wt%	0.04	0.04	0.40	0.42	0.11	0.12
SrO, wt%	0.02	0.03	0.14	0.14	0.04	0.05
BaO, wt%	0.06	0.06	0.11	0.10	0.07	0.07
Mn_3O_4, wt%	0.05	0.04	0.02	0.03	0.04	0.04
NiO, wt%	9.71	9.30			7.77	7.44
V_2O_5, wt%	60.70	60.10			48.56	48.08
Undetermined, wt%	0.83	0.61	0.31	1.44	0.73	0.78
Particulate size distribution						
Particulate Left Mesh, 1/2", wt%	15.70	17.27	15.98	15.45	15.76	16.91
Particulate Left Mesh, 1/4", wt%	14.56	13.24	17.22	17.78	15.09	14.15
Particulate Left Mesh, #4, wt%	3.88	2.69	4.04	3.92	3.91	2.94
Particulate Left Mesh, #8, wt%	8.74	7.10	15.74	16.38	10.14	8.96
Particulate Left Mesh, #14, wt%	21.20	19.20	14.41	14.43	19.84	18.25
Particulate Left Mesh, #28, wt%	20.87	22.07	11.03	10.85	18.90	19.83
Particulate Left Mesh, #48, wt%	5.89	8.59	8.29	7.73	6.37	8.42
Particulate Left Mesh, #100, wt%	4.61	4.88	6.94	6.40	5.08	5.18
Bottom, wt%	4.55	4.96	6.35	7.06	4.91	5.38

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - FUEL ANALYSES

August 10 - 11, 2004

Fuel Coal	80% Pet Coke / 20 % Pittsburgh 8		
Lab Number Date Time	Average	Count	Std Deviation
Proximate Analysis			
Moisture, wt%	5.27	2	0.0990
Ash, wt%	2.37	2	0.0594
Volatile, wt%	13.86	2	0.1598
Fixed Carbon, wt%	78.51	2	0.1994
Ultimate Analysis			
Carbon, wt%	81.75	2	0.5558
Hydrogen, wt%	3.65	2	0.0269
Nitrogen, wt%	1.94	2	0.0156
Sulfur, wt%	3.72	2	0.0297
Moisture, wt%	5.27	2	0.0990
Ash, wt%	2.37	2	0.0594
Oxygen, wt%	1.30	2	0.5883
Higher Heating, Btu/lb	14,083	2	3.2527
Total Chlorine, wt%	0.03	2	0.0057
Total Fluorine, ug/g	36.60	2	1.6971
Total Mercury, ug/g	0.05	2	0.0028
Total Lead, ug/g	4.20	2	0.5657
Moisture (oven), wt%			
Mineral analysis			
SiO_2, wt%	13.51	2	0.0594
Al_2O_3, wt%	6.49	2	0.0198
Ti_2O, wt%	0.56	2	0.0127
Fe_2O_3, wt%	8.46	2	0.2715
CaO, wt%	2.22	2	0.0354
MgO, wt%	0.37	2	0.0170
K_2O, wt%	0.41	2	0.0240
Na_2O, wt%	4.80	2	0.1216
SO_3, wt%	6.23	2	0.8655
P_2O_5, wt%	0.11	2	0.0028
SrO, wt%	0.05	2	0.0057
BaO, wt%	0.07	2	0.0014
Mn_3O_4, wt%	0.04	2	0.0042
NiO, wt%	7.60	2	0.2319
V_2O_5, wt%	48.32	2	0.3394
Undetermined, wt%	0.75	2	0.0354
Particulate size distribution			
Particulate Left Mesh, 1/2", wt%	16.33	2	0.8132
Particulate Left Mesh, 1/4", wt%	14.62	2	0.6675
Particulate Left Mesh, #4, wt%	3.42	2	0.6901
Particulate Left Mesh, #8, wt%	9.55	2	0.8372
Particulate Left Mesh, #14, wt%	19.04	2	1.1285
Particulate Left Mesh, #28, wt%	19.36	2	0.6534
Particulate Left Mesh, #48, wt%	7.39	2	1.4482
Particulate Left Mesh, #100, wt%	5.13	2	0.0752
Bottom, wt%	5.15	2	0.3323

ATTACHMENT H

Limestone Analyses

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY LIMESTONE ANALYSES

Limestone	Test #4		August 10 - 11, 2004		
Lab number	71-241477	71-241478	Average	Count	Std Deviation
Date	10-Aug-04	11-Aug-04			
Time	4 hours	4 hours			
Inerts, wt%	1.27	1.61	1.44	2	0.2404
CaCO3, wt%	97.55	97.23	97.39	2	0.2263
MgCO3, wt%	1.18	1.16	1.17	2	0.0141
Moisture, %	0.30	0.29	0.295	2	0.0071
Na, ug/g	0.01	0.01	0.01	2	0.0000
K, ug/g	0.01	0.01	0.01	2	0.0000
Pb, ug/g	3.00	1.00	2	2	1.4142
Hg, ug/g	0.110	0.100	0.105	2	0.0071
F, ug/g	17.00	12.00	14.5	2	3.5355
Cl, ug/g	220.000	250.000	235	2	21.2132
Particulate size distribution					
Particulate Left Mesh, #8, wt%	26.22	32.99	29.61	2	4.7871
Particulate Left Mesh, #14, wt%	14.33	16.60	15.47	2	1.6051
Particulate Left Mesh, #28, wt%	10.86	10.03	10.45	2	0.5869
Particulate Left Mesh, #48, wt%	10.66	7.34	9.00	2	2.3476
Particulate Left Mesh, #100, wt%	18.69	20.47	19.58	2	1.2587
Bottom, wt%	19.24	12.58	15.91	2	4.7093
Calcium Carbonate Equivalent	98.90	98.60	98.75	2	0.2121

ATTACHMENT I

Bed Ash Analyses

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - BED ASH ANALYSES

August 10 - 11, 2004

Bed Ash	Test #4		August 10 - 11, 2004		
Lab Number	71-241483	71-241484	Average	Count	Std Deviation
Date	10-Aug-04	11-Aug-04			
Time	4 hours	4 hours			
Unburned carbon, wt%	0.65	0.62	0.64	2	0.0212
Organic carbon, wt%	0.50	0.48	0.49	2	0.0141
Loss on Ignition @ 950 deg F	0.98	0.98	0.98	2	0.0000
CaSO4, %wt	61.34	64.57	62.96	2	2.2840
Sulfur, wt%	14.88	15.24	15.06	2	0.2546
Mineral analysis					
SiO2, %wt	0.16	0.12	0.14	2	0.0283
Al2O3, %wt	1.09	1.01	1.05	2	0.0566
TiO2, %wt	0.06	0.06	0.06	2	0.0000
Fe2O3, wt%	0.54	0.55	0.55	2	0.0071
CaO, wt%	56.55	56.57	56.56	2	0.0141
MgO, wt%	0.63	0.64	0.64	2	0.0071
K2O, wt%	0.02	0.01	0.02	2	0.0071
Na2O, wt%	0.01	0.01	0.01	2	0.0000
SO3, wt%	37.20	39.10	38.15	2	1.3435
P2O5, %wt	0.03	0.03	0.03	2	0.0000
SrO, %wt	0.09	0.09	0.09	2	0.0000
BaO, %wt	0.01	0.01	0.01	2	0.0000
Mn3O2, %wt	0.01	0.01	0.01	2	0.0000
V2O5, %wt	1.00	0.98	0.99	2	0.0141
Undetermined, %wt	0.98	2.81	1.90	2	1.2940
Particulate size distribution					
Particulate Left Mesh, 1/2", wt%	0.00	0.00	0.00	2	0.0000
Particulate Left Mesh, 1/4", wt%	0.22	0.13	0.18	2	0.0636
Particulate Left Mesh, #4, wt%	0.19	0.10	0.15	2	0.0636
Particulate Left Mesh, #8, wt%	2.72	2.36	2.54	2	0.2546
Particulate Left Mesh, #14, wt%	8.09	7.27	7.68	2	0.5798
Particulate Left Mesh, #28, wt%	13.93	13.33	13.63	2	0.4243
Particulate Left Mesh, #48, wt%	22.62	21.82	22.22	2	0.5657
Particulate Left Mesh, #100, wt%	26.68	31.08	28.88	2	3.1113
Bottom, wt%	25.55	23.91	24.73	2	1.1597

ATTACHMENT J

Fly Ash (Air Heater and PJFF) Analyses

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - FLY ASH ANALYSES

Fly Ash	August 10 - 11, 2004 Air Heater			August 10 - 11, 2004 Air Heater (Iso Kinetic)		
	Average	Count	Std Deviation	Average	Count	Std Deviation
Unburned carbon, wt%	0.50	2	0.1485	5.03	2	0.5233
Organic carbon, wt%	0.41	2	0.1485	4.39	2	0.6435
LOI @ 1742 °F (950 °C)	0.89	2	0.2828	8.73	2	0.5162
CaSO4, wt%	67.61	2	0.9758	41.06	2	0.3041
Sulfur, wt%	16.00	2	0.3041	9.80	2	0.0141
Ash analysis						
SiO2, wt%	0.12	2	0.0141	5.64	2	0.2192
Al2O3, wt%	1.68	2	0.0636	4.05	2	0.3253
TiO2, wt%	0.09	2	0.0000	0.16	2	0.0071
Fe2O3, wt%	1.26	2	0.1414	2.05	2	0.0141
CaO, wt%	53.27	2	0.6859	53.18	2	0.2475
MgO, wt%	0.59	2	0.0000	0.58	2	0.0354
K2O, wt%	0.05	2	0.0000	0.28	2	0.0141
Na2O, wt%	0.05	2	0.0141	0.11	2	0.0141
SO2, wt%	39.99	2	0.7566	24.48	2	0.0354
P2O5, wt%	0.03	2	0.0000	0.09	2	0.0707
SrO, wt%	0.08	2	0.0000	0.05	2	0.0566
BaO, wt%	0.01	2	0.0000	0.01	2	0.0000
Mn3O4, wt%	0.01	2	0.0000	0.02	2	0.0000
Undetermined	1.48	2	0.3748	9.33	2	0.8980
Particulate size distribution						
Particulate Left Mesh, #4, wt%	0.00	2	0.0000	0.00	2	0.0000
Particulate Left Mesh, #14, wt%	0.02	2	0.0212	0.00	2	0.0000
Particulate Left Mesh, #28, wt%	0.02	2	0.0283	0.00	2	0.0000
Particulate Left Mesh, #48, wt%	0.06	2	0.0071	0.00	2	0.0000
Particulate Left Mesh, #100, wt%	0.38	2	0.1273	0.00	2	0.0000
Bottom, wt%	99.53	2	0.1838	100.00	2	0.0000

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - FLY ASH ANALYSES

Fly Ash	August 10 - 11, 2004 Bag House		
	Average	Count	Std Deviation
Unburned carbon, wt%	6.11	2	0.0707
Organic carbon, wt%	4.81	2	1.1950
LOI @ 1742 °F (950 °C)	9.29	2	0.2758
CaSO4, wt%	40.45	2	0.5586
Sulfur, wt%	9.63	2	0.0283
Ash analysis			
SiO2, wt%	2.82	2	0.9546
Al2O3, wt%	3.64	2	0.4808
TiO2, wt%	0.18	2	0.0212
Fe2O3, wt%	2.41	2	0.0071
CaO, wt%	54.16	2	1.1597
MgO, wt%	0.64	2	0.0071
K2O, wt%	0.28	2	0.0283
Na2O, wt%	0.30	2	0.0495
SO2, wt%	24.08	2	0.0636
P2O5, wt%	0.03	2	0.0000
SrO, wt%	0.09	2	0.0000
BaO, wt%	0.02	2	0.0000
Mn3O4, wt%	0.01	2	0.0000
Undetermined	10.58	2	0.4667
Particulate size distribution			
Particulate Left Mesh, #4, wt%	0.00	2	0.0000
Particulate Left Mesh, #14, wt%	0.00	2	0.0000
Particulate Left Mesh, #28, wt%	0.00	2	0.0000
Particulate Left Mesh, #48, wt%	0.00	2	0.0000
Particulate Left Mesh, #100, wt%	0.08	2	0.1131
Bottom, wt%	99.92	2	0.1131

ATTACHMENT K

Ambient Data, Aug. 12, 2004 & Aug. 13, 2004

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY MET DATA

	Date:	August 10, 2004	August 11, 2004
	Start:	0930 hours	0800 hours
	End:	1330 hours	1200 hours
Characteristic Being Measured		**Values Used in Efficiency Calculation**	
Dry Bulb Temperature, North / South, deg F		86.19	83.71
Count		962	962
Standard Deviation		2.41	3.30
Wet Bulb Temperature, North / South, deg F		72.19	75.13
Count		962	962
Standard Deviation		0.81	2.14
Atmospheric Pressure, in Hg		30.15	29.99
Atmospheric Pressure, psia		14.75	14.68
Count		5	8
Standard Deviation		0.01	0.004

ATTACHMENT L

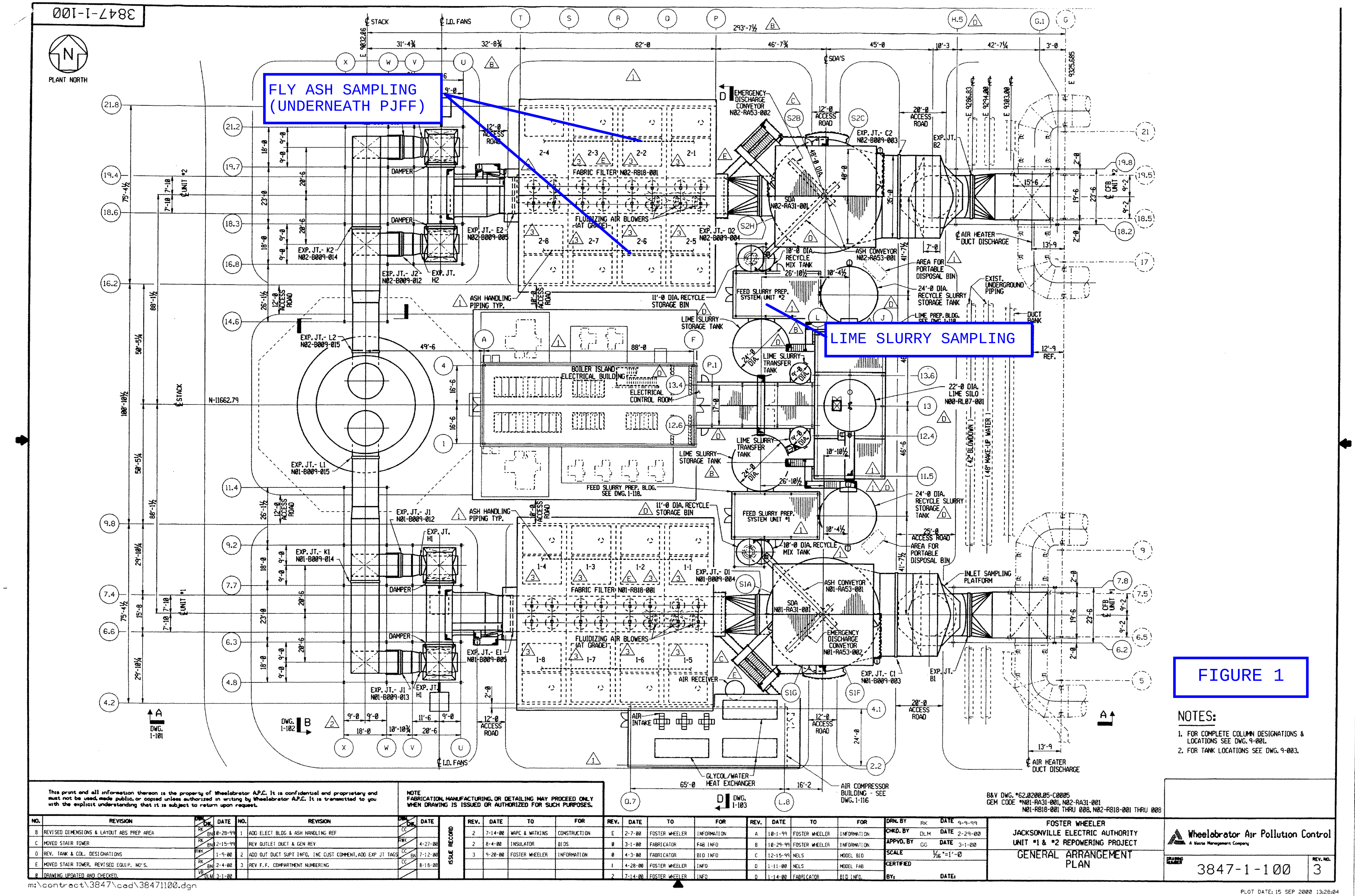
Partial Loads Ambient Data, Aug. 10, Aug. 11, 2004

JEA Northside Unit 2
Test #4
80/20 Pet Coke / Pittsburgh 8 Coal
SUMMARY - MET DATA, Aug. 12 - 13, 2004

Date	Time (hrs)	Temperature, deg F (dry bulb)	Temperature, deg F (wet bulb) Calculated	Dew Point, deg F	Relative Humidity, %	Pressure, in Hg	Pressure, psiA	RH calc to determine wet bulb
AUG. 12, 2005 (80% LOAD)								
12-Aug-04	0055	79.0	**75.00**	72.0	**79**	29.97	14.67	79
12-Aug-04	0155	78.1	**74.50**	72.0	**81**	29.96	14.66	81
12-Aug-04	0255	77.0	**73.80**	71.1	**82**	29.95	14.66	82
12-Aug-04	0355	77.0	**73.80**	71.1	**82**	29.94	14.65	82
12-Aug-04	0455	78.1	**74.50**	72.0	**81**	29.92	14.64	81
AUG. 13, 2005 (60% LOAD)								
13-Aug-04	0055	78.1	**74.50**	72.0	**81**	29.92	14.64	81
13-Aug-04	0155	77.0	**74.80**	73.0	**88**	29.92	14.64	88
13-Aug-04	0255	75.9	**74.30**	73.0	**91**	29.91	14.64	91
13-Aug-04	0355	77.0	**75.20**	73.9	**90**	29.90	14.63	90
13-Aug-04	0455	78.1	**76.30**	75.0	**90**	29.91	14.64	90

FIGURES

DWG40998 03-MAR-2004 14:48:45



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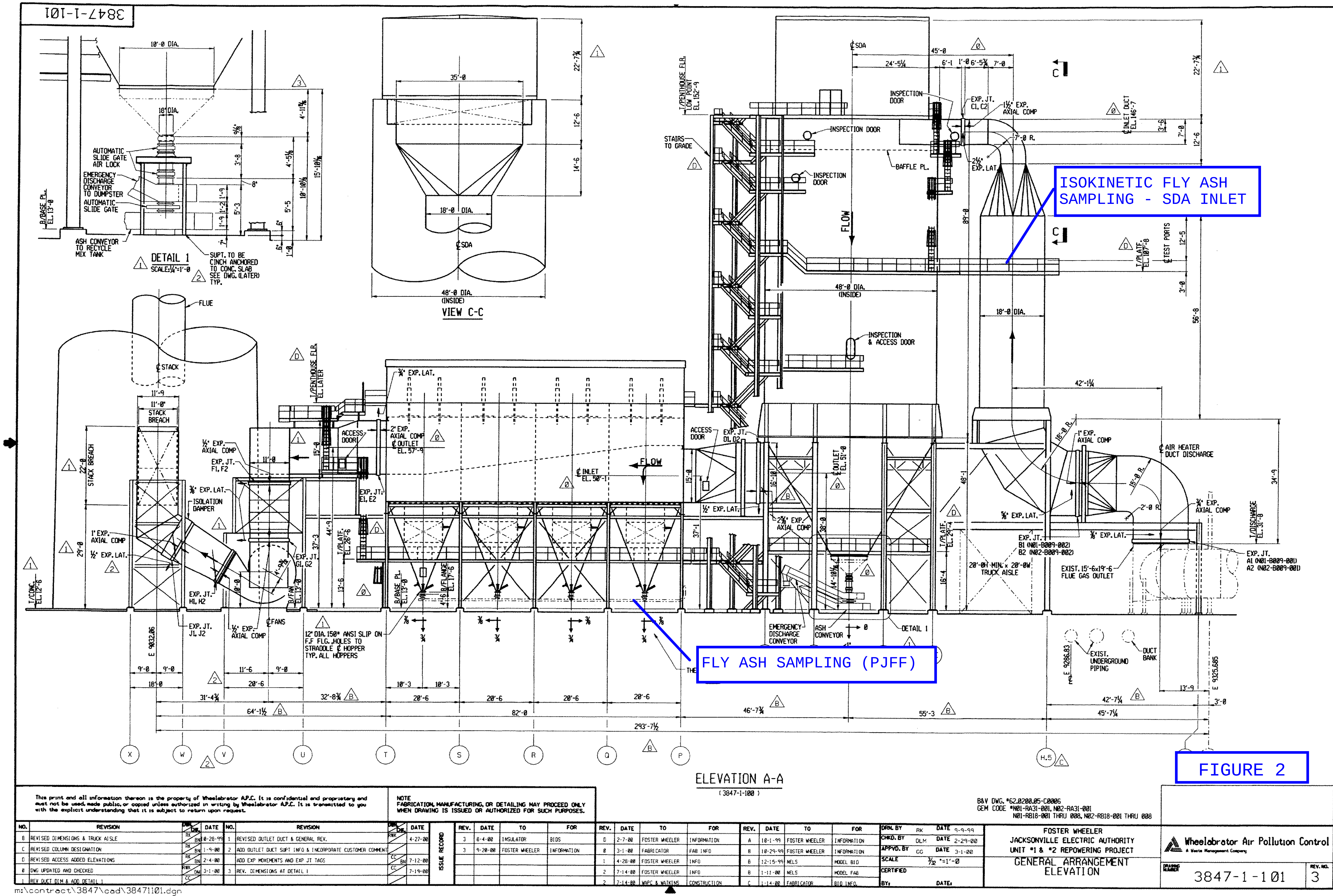

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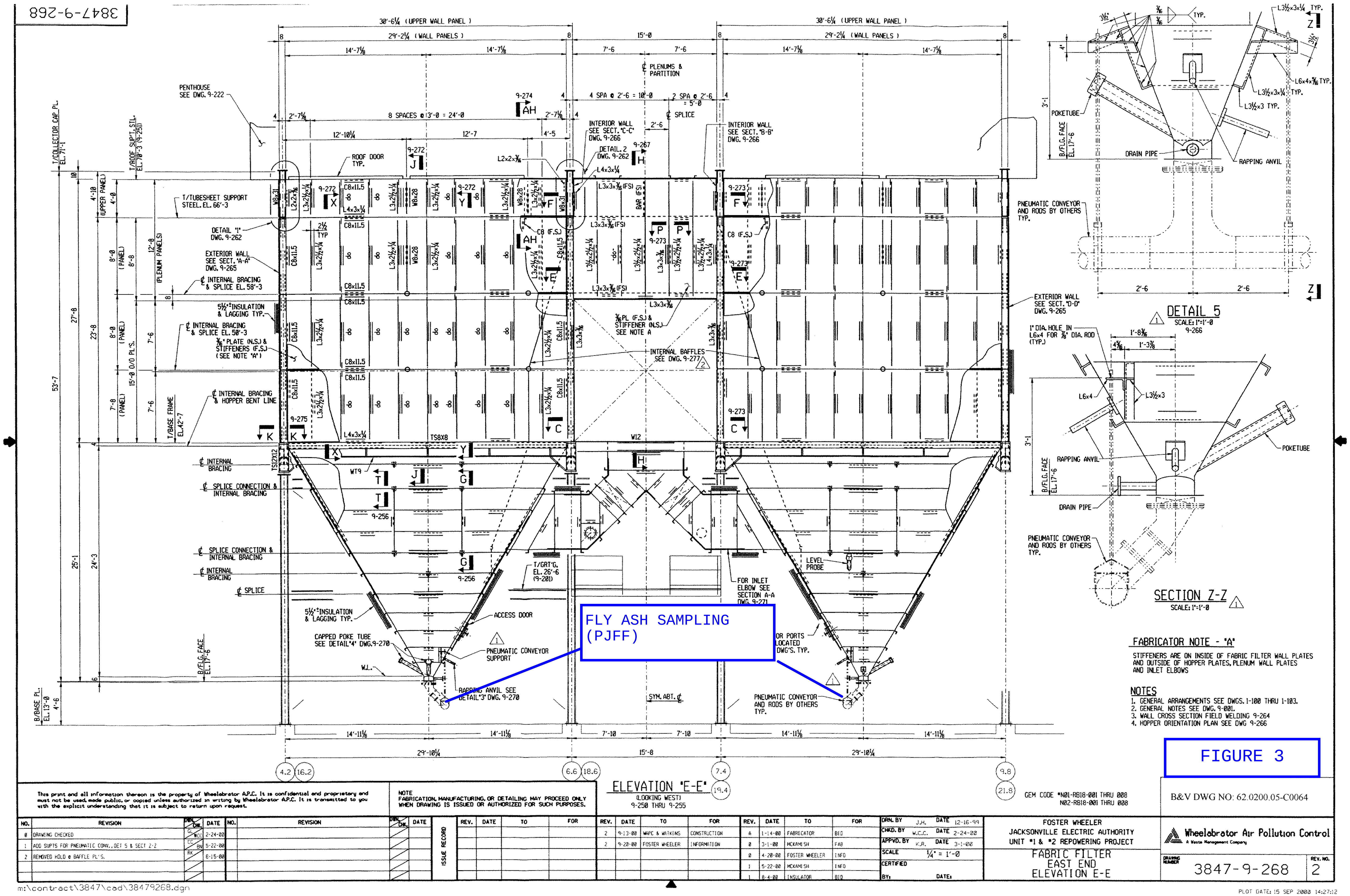
3847-9-268
FLY ASH SAMPLING (PJFF)
ELEVATION "E-E"
(LOOKING WEST)
9-250 THRU 9-255
DETAIL 5
SCALE: 1"=1'-0
SECTION Z-Z
SCALE: 1"=1'-0
FABRICATOR NOTE - "A"
STIFFENERS ARE ON INSIDE OF FABRIC FILTER WALL PLATES AND OUTSIDE OF HOPPER PLATES, PLENUM WALL PLATES AND INLET ELBOWS
NOTES
1. GENERAL ARRANGEMENTS SEE DWGS. 1-100 THRU 1-103.
2. GENERAL NOTES SEE DWG. 9-001.
3. WALL CROSS SECTION FIELD WELDING 9-264
4. HOPPER ORIENTATION PLAN SEE DWG 9-266
FIGURE 3
B&V DWG NO: 62.0200.05-C0064
FOSTER WHEELER
JACKSONVILLE ELECTRIC AUTHORITY
UNIT #1 & #2 REPOWERING PROJECT
FABRIC FILTER
EAST END
ELEVATION E-E
Wheelabrator Air Pollution Control
3847-9-268
m:\contract\3847\cad\38479268.dgn

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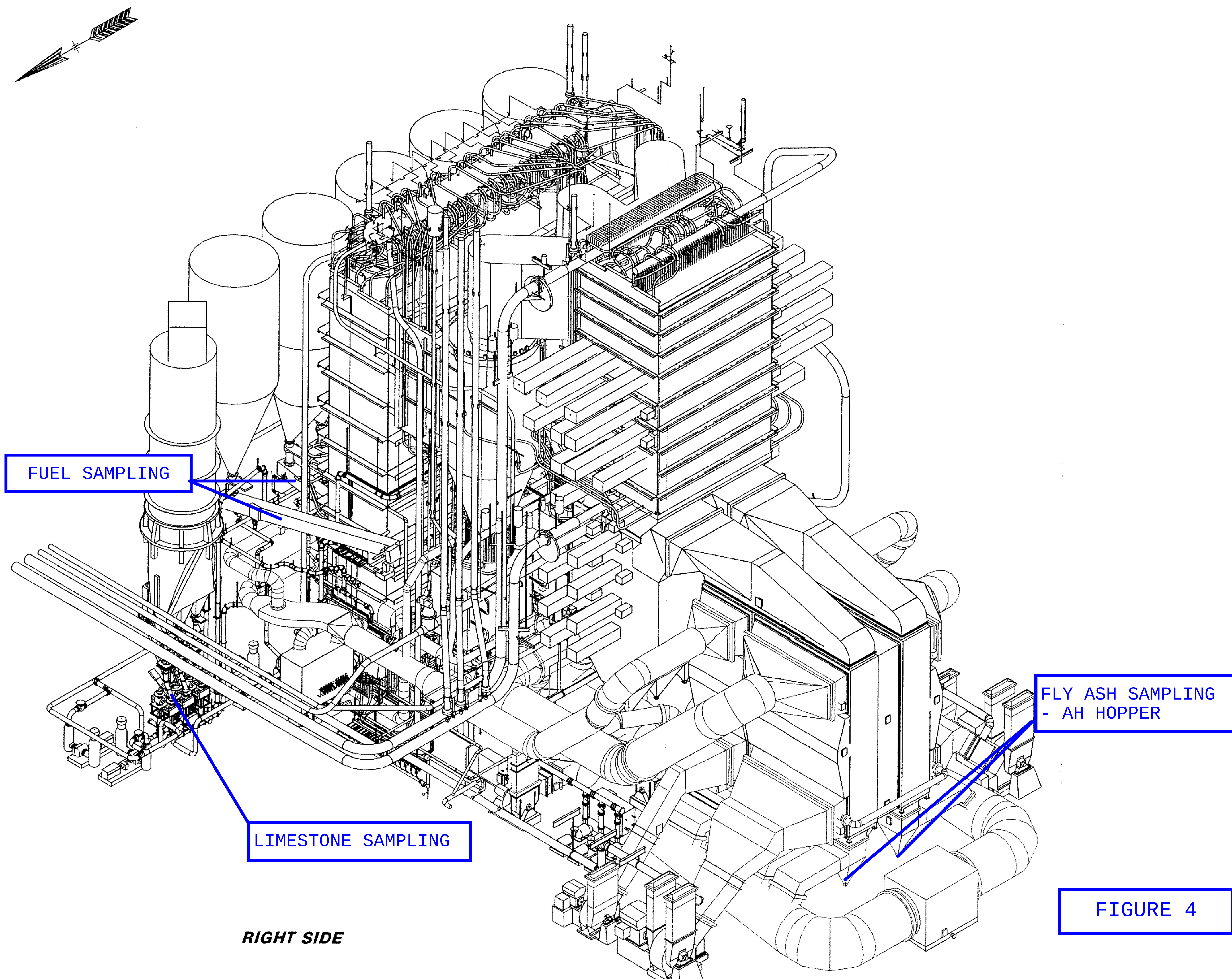

FIGURE 4

NOTES

1. DO NOT SCALE THIS DRAWING. USE FIGURE DIMENSIONS ONLY.
2. ABBREVIATIONS USED ON THIS DRAWING ARE IN ACCORDANCE WITH AMERICAN STANDARD "ABBREVIATIONS FOR USE ON DRAWING".
3. FOR ADDITIONAL NOTES & REFERENCE DRAWINGS SEE DRAWING 43-7587-5-50

B&V Dwg No: 62.3401.05-C0012

REV.	DATE		DESCRIPTION
C	6-23-00	JHM	UPDATED DRAWING
B	5-26-99	JHM	DESIGN UPDATE
A	3-29-99	JHM	FIRST ISSUE

REVISIONS

GENERAL ARRANGEMENT
UNIT 2
ISO VIEW (RIGHT SIDE)

NORTHSIDE UNITS 1 & 2 REPOWERING PROJECT
Equipment No.:
B&V Drawing No.: 62.3401.05-C0012

43-7587-5-53 C

JHM 3-16-99 200758700 UNIT 2 DOE
200761000 UNIT 1 JEA

FOSTER WHEELER ENERGY CORPORATION

THIS IS A PDMS DRAWING.
REVISE ONLY IN PDMS

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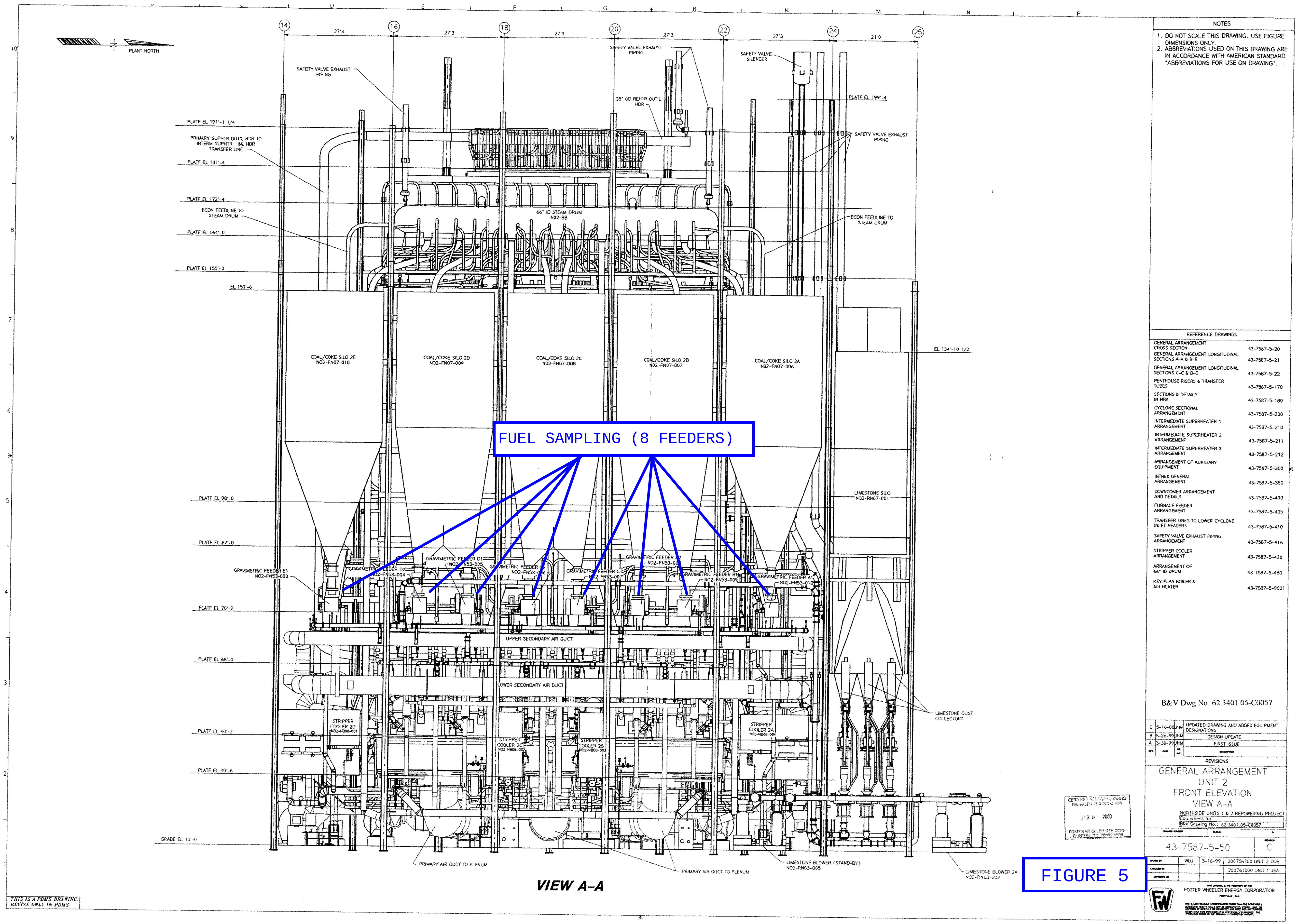

FIGURE 5

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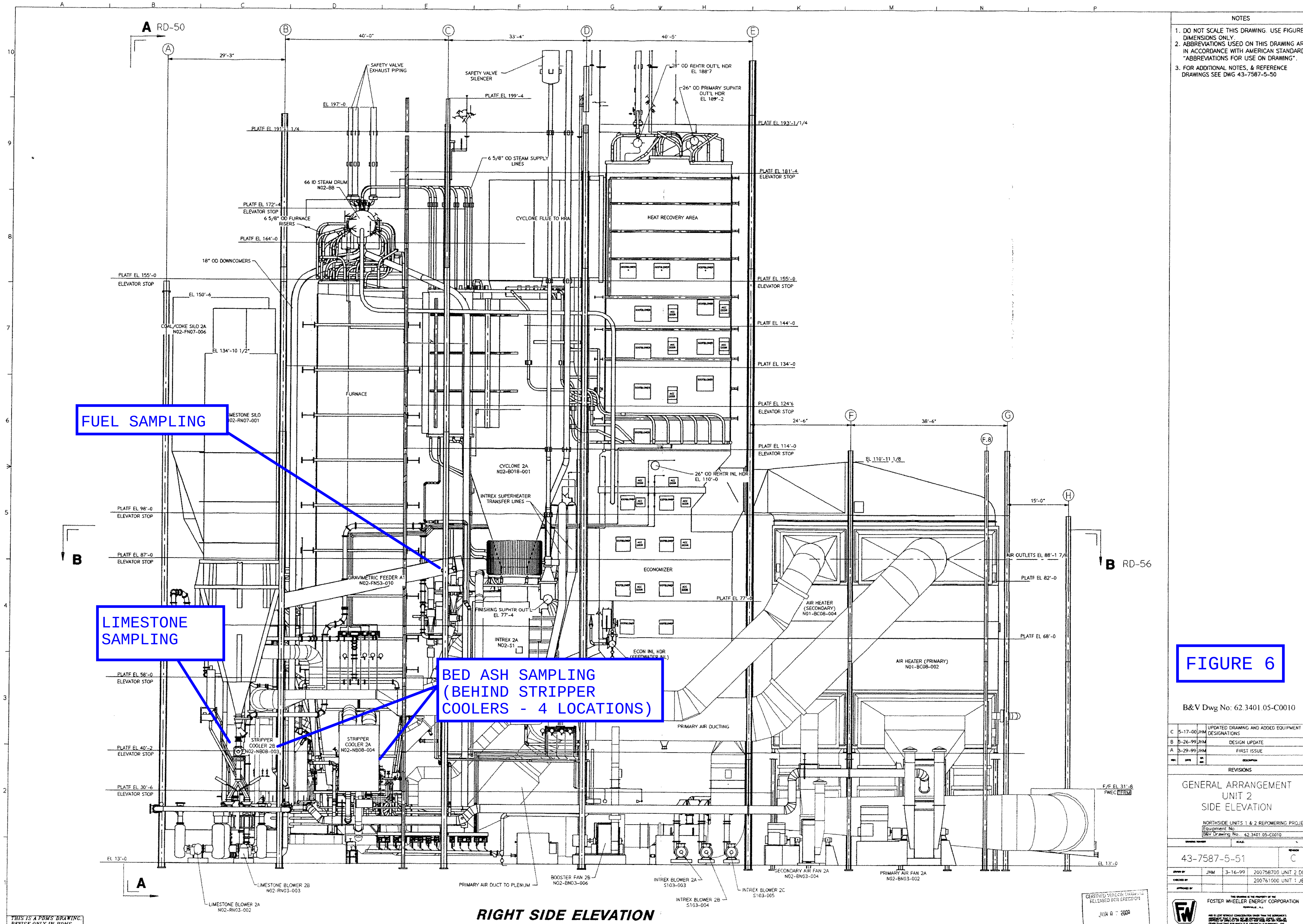

FIGURE 6

B&V Dwg No: 62.3401.05-C0010